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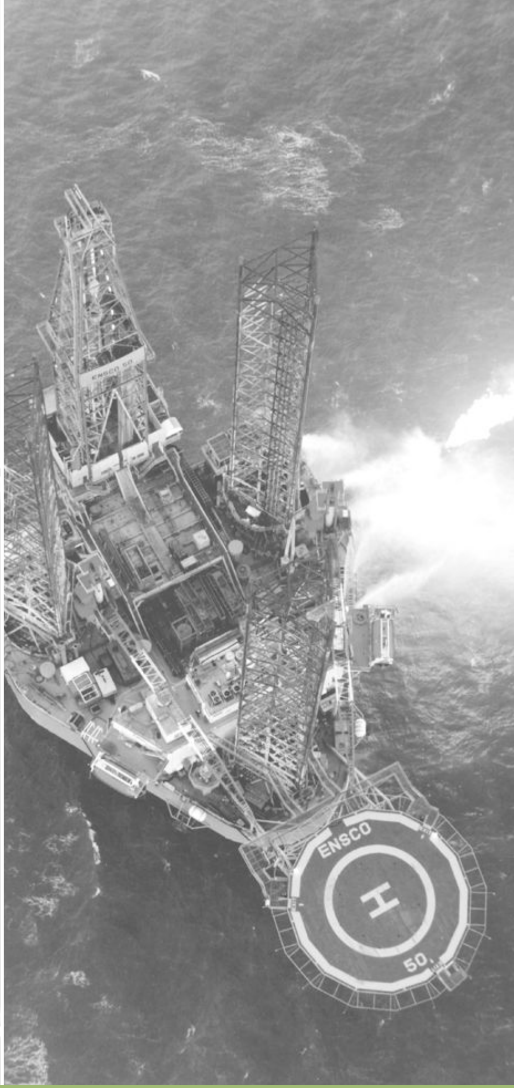

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ENERGY SUPPLY IN THE POST-MAUI ERA

an investigation into thermal fuel options and their contribution to energy security

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executive summary

This study is a continuation of earlier CAE analyses of the New Zealand energy situation, and the issues surrounding primary energy supply in particular. The study offers a comprehensive discussion of the risks New Zealand faces in the post-Maui era, especially with regards to the supply and consumption of gas. The premise of the report is that gas exploration in New Zealand in recent years has declined due to the large reserves and the low cost of gas from the Maui field. As Maui comes to the end of its productive life, the imbalance between gas demand and gas supply will intensify.

The key distinction between the Maui era and the present is that proven developed gas reserves are now low relative to the rate of consumption. We argue that New Zealand needs to find thermal energy solutions that can balance energy security against higher costs while achieving energy diversity through planned investment in alternative strategies.

The inherent difficulty faced by the New Zealand energy market is one of scale; in a small market the likelihood for market dominance by one thermal fuel is high. For major energy users the future price of gas will be critical. Higher costs will also adversely impact on the competitiveness of the primary production and processing sectors and hence on the economy as a whole.

The purpose of this investigation, therefore, has been to inform government policies and industry strategies on the implications of various supply options and the public policy imperatives that are needed to underpin future planning and investment. To achieve this, the report seeks to develop a clear understanding of the primary technical, economic, and transactional requirements that might frame future decision-making. In particular this study seeks to provide an analysis of:

- The state of the New Zealand thermal fuels market.
- How the indigenous natural gas sector might develop to meet domestic demand during the transition to "new" thermal fuels post-Maui.
- How other thermal fuels may be used to supplement indigenous gas supply to meet any supply gap and enhance security.
- How these options may be deployed should indigenous gas supply prove inadequate.
- The possible effects of "high assurance solutions," such as conventional LNG implementation, on the vitality of exploration and development.
- The optimal energy supplies strategy that balances risks and opportunities for the New Zealand economy.

Due to low prices for gas during the Maui era, New Zealand gas exploration efforts were insufficient to maintain adequate reserves and allow an ordered market response to the depletion of the Maui field . Today, New Zealand's gas reserves represent just nine years of production. Depending on the assumptions used for demand, this could extend for another five years. New, as yet undiscovered, reserves will be needed early in the next decade.

However, with increasing gas prices the incentives for gas exploration have dramatically improved. New Zealand thus has a window of opportunity of some few years before any decision needs to be made on the next tranche of fuel supply. The fundamentals for further gas exploration success are good and, with a higher level of exploration activity, there are good prospects for restoring New Zealand's gas inventory to a level that would improve energy supply security and give energy markets a higher level of certainty.

The alternative is to supplement a dwindling indigenous natural gas supply with thermal fuels from other sources.

An LNG project to meet an annual gas gap of about 80 PJ a year is at the lower end of the minimum economic scale in a capital-intensive industry. Such a scale is large as a proportion of the whole New Zealand gas market, but is only 0.2% of current world LNG trade. The most likely contract structure would involve a long-term commitment to this volume of gas, thereby reducing the size of the market available to indigenous suppliers.

A storage and re-gasification facility of this scale is estimated to cost approximately US$280 million plus infrastructure costs of between US$60m and US$90m. Assuming an FoB price of around US$3.30/GJ at a prevailing oil price of US$30/barrel, and with a shipping tariff of around US$0.33/GJ, and an exchange rate of NZ$1 = US 55 cents, the indicative cost of LNG delivered into New Zealand is expected to be in the region of $8.70/GJ, The deployment of an alternative option explored in this study of a re-gasification vessel reduces this cost to about $8.05/GJ.

Macro-economic modelling of the New Zealand economy under this scenario predicts that LNG imports would cause terms of trade to worsen, with additional exports needed to avoid an external deficit. It is predicted that real exports would rise by 0.4%, pulling resources out of private consumption which falls by 0.3%; which is around $340 million per annum in 2004 prices.

The real cost of LNG imports in 2017 is predicted to be $600 million. Of this about $300m is paid for by higher exports and lower private consumption, leaving about $300m to be accommodated by a change in the mix of imports. Gas prices would be higher than indigenous fuel costs and demand for both gas and electricity would be lower.

While there are significant uncertainties around these projections, the commercial viability of LNG importation into the small New Zealand market is considered to be doubtful at present. A premature decision to import LNG would also act to discourage local gas exploration and possibly coal development, primarily for scale reasons, and would lead the country towards higher future energy costs and diminished economic performance. Whilst attractive from a security of supply perspective, an LNG option also raises significant public policy issues. There are alternatives deserving of more attention.

Coal has the potential to reassert itself in the thermal fuels market for both electricity generation and industrial use. Resources are well known; it can be stockpiled, is proximate to main users and is highly tradable. Economically recoverable resources in New Zealand are estimated at 150,000 PJ, or about 75 times current gas reserves. At current rates of consumption there is enough for 230 years, excluding the vast Southland/Otago lignite resource.

Coal also has potential economic benefits in giving much-needed fuel diversity in electricity generation and offers significant flexibility for a market place that is already constrained by seasonal demand profiles and dry-year effects within the electricity sector.

Modelling of the electricity market shows that the use of LNG as a fuel would result in materially higher electricity prices than the other main alternatives of indigenous gas and coal. In addition, there is there is very little difference in projected wholesale electricity price between using coal and indigenous gas at expected carbon charges. This exposes another significant commercial risk for LNG, because coal can always compete.

This investigation concludes that New Zealand should be extremely wary about importing high-cost fuels, which could lead to over-dependence on one type of thermal fuel. Security of energy supply does not require our economy to lock into any one option. Dealing with supply shortfall is not simply a question of reducing risk at any price or seeking certainty; instead, it demands responses that will extend New Zealand's primary energy resource base, restore inventories to cover a strategic reserve capacity and enable long-term investment in alternative sources.

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introduction

New Zealand's energy sector has now firmly entered a transition period between an era of abundant gas supply since the Maui field was developed in 1979, and a post-Maui era that begins once the giant field is depleted some time around 2010. Our entering this transition was heralded by the redetermination of the Maui gas reserves and renegotiation of the Maui Contract.

The work reported here is a continuation of earlier CAE published analysis of the New Zealand energy situation, especially the issues surrounding primary energy supply. The report gives a comprehensive discussion of the risks and options New Zealand faces in the post-Maui era, and examines the various thermal fuel supply options available. The investigations described have been sponsored by a consortium of industry interests and the Ministry of Economic Development.

In doing so, this study provides the first complete and independent analysis of the thermal fuels market in New Zealand. The new information presented in this summary report is underpinned by a series of technical investigations, documented in a detailed project report prepared for the sponsor group.

The purpose of the study is to inform Government policies and industry strategies of the balances of opportunity, cost, risks and benefits arising from choosing certain pathways. To achieve this, the study seeks to develop a clear understanding of the primary technical, economic, contractual and regulatory decisions required to realise the most attractive of the options available.

In particular, the study develops objective analyses of:

- the state of New Zealand thermal fuels markets
- how the indigenous natural gas sector might develop to adequately meet domestic demand in the transition from the Maui era to a "new" thermal fuels supply environment in the post-Maui era
- how other thermal fuels options such as LNG, coal or CNG may be used to supplement indigenous gas supply to plug any supply gap and enhance energy security, including dealing with hydro shortages in the electricity system
- how these options may be deployed should indigenous gas supply prove inadequate in the longer term
- the possible effects of "high assurance" solutions, such as a standard LNG implementation, on the vitality of exploration and development, on the energy sector and on the overall competitiveness of the economy
- the optimal energy supply strategy that balances the risks and opportunities for the New Zealand economy.

The perspectives taken are market-based rather than technical, and the scenario-based approach adopted is more top-down than bottom-up. The investigation is thus primarily at a national level, and while some commercial issues relevant to future options are investigated, the study does not aim to present enterprise-level analysis. The effects and infrastructure implications of various options are assessed wherever possible in relation to some industrial sectors, electricity generation and prices, and the economy as a whole.

A base case examines the prospects of continuing to rely on adequate supplies of indigenous natural gas at reasonable and competitive prices. Increasing scarcity and consequential higher prices are currently leading to more, if belated, exploration for oil and gas. There is a small and urgent time window for the sector to find and develop new indigenous gas resources before alternative thermal fuels supply options will be necessary. The feasibility of this base case is assessed through analysis of the undiscovered and undeveloped New Zealand gas resource and of the potential to develop the domestic exploration and production sector to a level at or beyond that held during the Maui era.

In an LNG scenario, gas importation is identified as the counterfactual if indigenous natural gas reserves continue to fall short of potential consumption. Because this is a potentially viable means of minimising the risks to security of energy supply, whilst avoiding the supply security uncertainties associated with alternative courses of action, this option and its impacts are investigated in some detail. A high-level characterisation is presented of the implications of importing LNG, touching on minimum efficient scale, the extent to which existing infrastructure can be used or will be stranded, new capital and infrastructure requirements, contractual issues, planning and lead-time issues, and the potential downstream and economic impacts of proceeding along these lines.

Due primarily to the scale requirements and the relatively high capital requirements and cost of conventional LNG projects, and the uncertainty of indigenous gas exploration success, other options are also examined to improve the thermal fuels situation; either in isolation or as a portfolio of measures. These include opportunities for increased coal utilisation, whether indigenous or imported, and opportunities for importing distillate fuels or CNG.

The time horizon for the study is the decade to 2015. Analysis extends beyond this time as it applies to long-lived infrastructure and assets, and to lead times in resource and project realisation. Prices are in $NZ unless otherwise stated.

energy and the economy

The Maui era was characterised by strong economic development underpinned by low energy costs which gave the New Zealand economy a competitive advantage in energy-intensive activities. The economy and a large portion of its infrastructure was tuned to major investments that were made in association with development of the Maui field. These led to the establishment of natural gas as New Zealand's primary fuel source for new electricity generating plant, the development of a gas processing industry, and significant substitution of foreign oil in the domestic fuels market. At its peak, Maui produced a quarter of New Zealand's energy requirements. The country was 65% self-sufficient in transport fuels and had close to net self-sufficiency in oil.

However, the other side of this equation was the failure at national level to address this country's future energy priorities. CAE has previously characterised this failure as a lost opportunity, leaving New Zealand exposed to economic risk and the many vagaries of global energy markets. What the post-Maui era will bring is both troublingly, uncertain and critically important to New Zealand's future economic performance.

With the impending depletion of the Maui gas field, and little in the way of new resources to replace it in terms of quantity and flexibility in deliverability, New Zealand faces a transition period of considerable energy supply uncertainty as increasingly scarce natural gas resources lead to price increases. This looming gas shortfall has arrived while a second transition, towards a less centralised and more competitive electricity sector, is being worked through. The most important combined effect is uncertainty over the framework within which relevant Government policies and enterprise strategies are developed. This uncertainty has in turn led to:

- delays in expansion commitments of new generation plant required to satisfy growing electricity demand
- Government underwriting of Genesis Power's e3p Huntly project
- delays in the commitment to the expansion of primary processing industries
- loss of competitive edge in some of these industries and signs of some industry investment moving offshore.

Uncertainty over the commercial environment in the energy sector makes investors insecure which, in turn, tends to suppress investment. If this situation persists, it threatens the energy security of users which has flow-on effects through the economy.

THE IMPORTANCE OF ENERGY SECURITY

New Zealand's current position

The notion of energy security is based on society's expectation that an adequate and continuous supply of energy at reasonable prices can be maintained. The expectation is not only for the immediate future, but also for an orderly transition to future energy arrangements that allow continuing improvements to our quality of life through economic growth whilst ensuring environmental impacts are at acceptable levels.

A range of recent indicators and events suggest that New Zealand's energy security is rather lower than might be desirable. These include:

- insufficient thermal generation capacity to cover reduced hydroelectric output during periods of low inflows, such as in 2001 and 2003.
- urgent investment by central government in the recommissioning of the Whirinaki power station, on behalf of the Electricity Commission while it was still being established, which many suggest is sub-optimal.
- the difficulties of securing necessary investment in infrastructure modernisation and of facilitating ongoing energy developments, exampled by the necessity for Government provision of fuel supply risk cover to enable a final investment decision for the construction of additional gas-fired generation capacity at Huntly (e3p).
- oil stocks being lower than required by the International Energy Agency agreement

which New Zealand has ratified.

- lack of arrangements to deal with the consequences of the redetermination of economically recoverable reserves associated with the Maui gas field, with consequent uncertainties reverberating throughout the energy sector.

The Maui redetermination has drawn overdue attention to the fact that the current inventory of proven natural gas reserves in this country has fallen below a satisfactory level. In terms of the threat to energy security, risk perception has moved rapidly from "negligible" to "high".

Barriers to improvement

The difficulty for New Zealand is that its past history of dependence on Maui gas and historical reliance on hydro for electricity generation has significantly constrained incentives for the development of alternative fuel sources. The resulting lack of diversity makes it especially important to ensure all options are given careful consideration during the transition to a post-Maui economy.

To do so requires an understanding of the extent and nature of New Zealand's energy resources, our pattern of energy use and the likely implications to the New Zealand economy of unexpected disruption to supply or future price volatility.

The spectre of "peak oil" further complicates the issues. The strongly held belief amongst some that existing known inventories of oil and gas will not be able to be supported by future discovery and development reinforces a public perception of an emerging energy gap. New Zealand is not exempt from this view despite the lack of a sustainable exploration effort in this country over the last 25 years and the fact that most of our petroleum basins are hardly explored.

This lack of knowledge and understanding of New Zealand's energy resources has already manifested itself in short-term interventions by Government in the energy market. It is important for the country as a whole that the future development of energy policy and any interventions that flow from that policy are based on the strongest possible foundations of information and analysis.

The balance of risk

As a country, we need to distinguish between a potential short-term energy shortfall and the essential strands to securing a sustainable energy future. This future can be defined by three fundamental requirements:

- extending New Zealand's primary energy resources;
- securing an acceptable level of strategic reserve capacity; and
- planning long-term investment in alternative strategies.

Strategic energy reserves are taken here to mean a ratio of reserves to production that is sufficient to support an orderly market. The appropriate level of the reserve ratio depends on the risk appetites of the major industry players (including users), and may also be backed by the Crown's perspective of its sovereign risk.

For most developed economies, the reserve ratio is not as important as for New Zealand because of their capacity to trade in the global marketplace. New Zealand is a small market that is physically distant from major trading hubs. We have no prospect of trading electricity internationally and no realistic ability to be anything other than a price taker in international fuel markets.

At the one end of the energy security scale, certainty of supply can be achieved by investing in "gold-plated" solutions that will guarantee supply but at the expense of economic efficiency. At the other end, higher supply risk might be accepted but balanced by lower energy costs and improved competitiveness. The challenge at a national level is to achieve the right balance, given existing energy supply circumstances and fuel inventories.

Identifying a balance position requires considering the desire for certainty, the need for economic competitiveness, the national tolerance for risk, the adaptability of energy consumers to change their existing patterns of energy use and, finally, the economic benefit that derives from diversity in supply.

This study examines the balance of risk in relation to the crucial thermal fuel component of New Zealand's energy security. The relative value of fuel options depends on factors such as location of the resource relative to energy markets, economic impositions such as a carbon tax, and development costs associated with attainment of environmental and safety standards. In the case of petroleum resources, including natural gas, it may be possible to add to the indigenous inventory; in this study we consider the commercial incentives for doing so under various scenarios.

THE PLACE OF THERMAL FUELS IN THE ECONOMY

New Zealand's primary energy supply is roughly 750 PJ/year. Natural gas, three quarters of it historically from Maui, contributed approximately 30% of this in 2002, dropping to about 20% now. The sheer size and production capacity of the Maui field relative to the size of the New Zealand gas market has, until recently, delivered plentiful gas to reticulated users, electricity generators and petrochemicals feedstock industries at a price essentially fixed in the mid-1970s.

Depletion of supply from the Maui field has thus had an immediate and material effect on the future availability of thermal fuels, both for direct use to supply process and low-grade heat in the industrial, commercial and domestic sectors, and for electricity generation. Thermal fuels include gas and its derivative LPG, coal, oil, and various petroleum distillates, as well as renewable energy forms such as geothermal energy and biomass.

As a legacy of the Maui era, about a quarter of New Zealand's electricity is produced from gas, with gas-fired power stations consuming about 40% of natural gas production. When hydro electricity is constrained, thermal fuels generate up to a third of our electricity. New Zealand's thermal generation system is anchored by power stations at Huntly (1000 MW), Stratford (355 MW), Otahuhu B (380 MW), and New Plymouth (400 MW). While other gas-fired and oil-fired plants are generally only used in hydro-firming, demand peaking, and other back-up roles, there is increasing pressure on them to supply base load.

About one third of New Zealand's energy use is associated with producing heat by various means using a range of thermal fuels. Major industry sectors that require some form of process heat include forestry, basic metals, fertiliser, meat and dairy processing.

In addition, about one third of electricity production is used for industrial, commercial and domestic heating. Industrial use of electricity is dominated by dairy production and processing, wood production, and the manufacture of meat products, pulp and paper, aluminium and methanol. Because many industries require both heat and electricity, the drive for efficiency has resulted in growing uptake of cogeneration, using thermal fuels to produce both forms of energy from the same source. In the residential sector, energy for hot water and heating is mainly supplied from electricity.

Despite tighter supply and rising prices, gas remains the preferred fuel for new electricity generation plant and, until the redetermination of the Maui field, gas demand had been increasing as new combined-cycle and gas-fired cogeneration plant came on stream. As New Zealand's developed gas reserves dwindle, our capacity to meet this level of demand has only been possible because the dual-fuel Huntly power station has switched from gas to coal, underlining our dependence on thermal fuels.

Key questions for the energy sector are the extent to which oil and gas from other indigenous sources might supplement current Maui reserves and the contribution to primary energy supply that alternative thermal fuel supply sources might make.

THE THERMAL FUELS GAP AND MARKET RESPONSES

In early 2003, a redetermination of the remaining economically recoverable reserves (EER) in the Maui field was 14% less than had been estimated in 1989. This downwards revision had effects and implications for the economy far beyond what this simple figure suggests. Although these problems already existed, they were masked by the nature of the Maui Contract.

Apparently quite suddenly, New Zealand faced:

- a supply gap in indigenous natural gas from early in the next decade unless new discoveries are made

- a consequential impending supply gap in electricity as both the supply and price of natural gas as a generation fuel became highly uncertain and forestalled needed capacity expansion
- a severe degradation of energy security conditions.

The gas gap arose because the excess supply capacity of the Maui field and associated low gas prices discouraged gas exploration at a level that could sustain the rate of consumption. New Zealand's gas reserves inventory was run down (Figure 1, Table 1) and there were no longer sufficient reserves to satisfy existing demand. With the accelerated depletion of Maui came steeply rising prices as gas buyers bid for diminishing reserves.

The gas gap is, in effect, a thermal fuels gap because of the unwillingness of the market so far to commit to alternatives unless fuel switching is an option.

The nature of the Maui Contract also resulted in serious impediments to efficient rationalisation of the market. In the absence of a robust public policy framework, the market stalled as participants appeared paralysed by the new environment. After a period of readjustment and reassessment of the new market situation, and as existing supply contracts expire, new gas contracts are now being struck at prices far higher than those which prevailed a year or two ago.

With increasing scarcity and steeply rising prices has come demand destruction from lower-value users such as petrochemicals manufacture. Where there is an immediate ability to switch fuels, there has been substitution away from natural gas to alternatives such as coal. Fuel switching has been especially notable in the case of the Huntly power station which has switched from being substantially gas-fired to being entirely coal-fired. The dairy processing industry is also turning increasingly to coal. Demand destruction and fuel switching have resulted in natural gas use falling from its peak of about 240 PJ/year in 2002 to less than 150 PJ/year now.

Even at this level, the reserves situation and future deliverability of indigenous gas is insufficient to meet demand. Despite the drop in consumption, the hydro shortage in the winter of 2003 highlighted the unpreparedness of the energy sector to deal with supply shocks. The hydro shortage combined with the inability of gas-fired generation to make up the shortfall meant that coal had to be imported, at short notice and sourced on the spot market, to avoid major electricity supply disruptions.

There have been other serious but less obvious effects of this thermal fuels gap. Investment decisions for much needed incremental thermal electricity generation capacity have been delayed and, in discussion with major industry players during the course of this study, there has been some indication that industry investment in New Zealand has been deferred because of uncertainty in fuel supply.

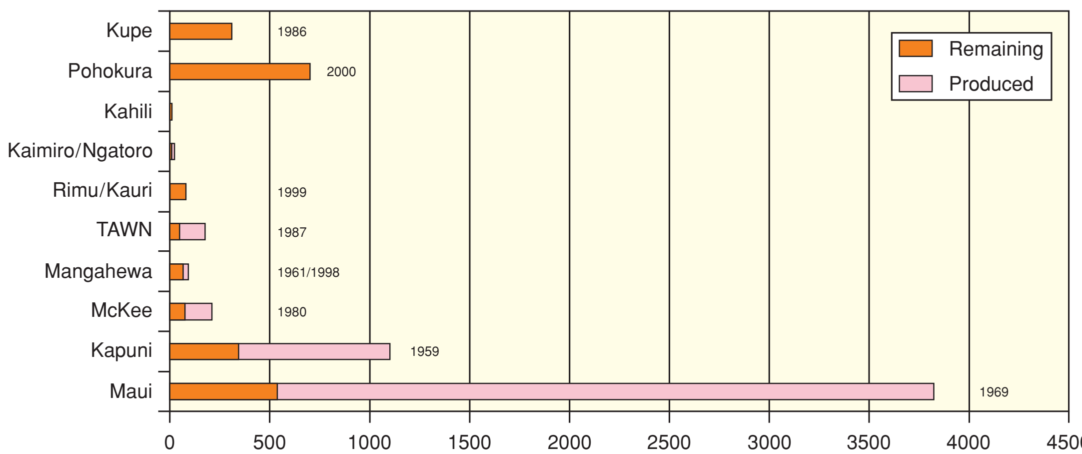


Figure 1: New Zealand gas reserves showing the depletion of reserves during the Maui era

As the energy sector continues its transition from the certainty, flexibility and low prices of Maui supply into the post-Maui environment, the challenge is to find strategies and policies that best:

- mitigate the impact of rising energy costs on the economy
- maintain as much flexibility as possible
- balance the risks and opportunities for the New Zealand economy.
- improve New Zealand's energy security.

These issues form the catalyst for this current study. The unsatisfactory thermal fuels situation that has evolved is beginning to manifest itself in significant downstream effects. An understanding of the implication of different response options is critical to improving national energy security.

It is thus important that we re-examine current industry strategies and offer a framework for future planning and investment.

the indigenous gas scenario

The indigenous gas scenario examines the proposition that New Zealand's growing thermal fuel requirements could be met through ongoing discovery and development of natural gas resources within our own territory. The scenario initially sets up a natural gas demand side perspective against which supply potential and attendant uncertainties can be assessed; then develops an indigenous natural gas supply and demand equation with plausible assumptions regarding the potential of New Zealand's gas resource endowment.

A likely price path for natural gas, and the consequential impacts on the New Zealand energy and industrial sectors are addressed in a later section of the report. Because of the importance of natural gas for electricity generation, the impact on the electricity sector, including downstream impacts, is also analysed. The analysis assumes no significant changes to the regulatory or market environments of the energy sector.

THE DEMAND SIDE PERSPECTIVE

Demand for natural gas in New Zealand can be broken down into four categories; differentiated by substitutability and inferred threshold values at which buyers would be expected to withdraw demand.

The first, highest value tranche of about 65 PJ/year is for reticulated direct use (domestic, commercial and industrial) and associated cogeneration of electricity. It cannot be easily substituted or readily deferred, and it seems unlikely that any significant fraction of this demand would be shed readily given that the electricity alternative is likely to rise in price in proportion to gas, and that major capital investment would be required to convert to coal, liquid, or other fuels.

The second tranche of up to 44 PJ/year is used by existing gas combined cycle (GCC) power stations. These are non-substitutable but their utilisation varies as a function of electricity price, so that the demand is deferrable until called into the electricity market. During periods of high hydroelectric generating capacity these stations are less likely to be used so that their owners can conserve their entitlements to gas for use in periods of higher power prices.

The third tranche is the large petrochemical demand capacity (predominantly Methanex but also Ballance Agri-Nutrients) of about 100 PJ/year neglecting progressive moth-balling. This is also deferrable but not substitutable, and seems likely to compete for available gas above the 65 PJ/year of core demand except when gas prices are high[1].

The remaining demand capacity is represented by thermal electricity plant with the capacity to switch fuels: the Huntly and New Plymouth power stations. We assume that these plants will probably remain out of the gas market for as long as supplies are short.

Three demand cases are depicted in this scenario (see Figures 2-4) as a plausible set of projections without attributing any particular likelihood of outcome:

- full petrochemical manufacture at 2001 levels
- limited petrochemical manufacture at approximately current levels
- closure of gas-based petrochemical plants.

These demand projections are overlaid on the various gas supply scenarios developed below.

NATURAL GAS PRICES AND DEMAND ATTRITION

With the redetermination of the Maui Contract reserves, negotiation of successor arrangements, and the depletion of the Maui field, prices have risen to reflect both the resulting scarcity and the emergence of a

1 For example, although Methanex's entitlements to Maui gas (which comprised most of their feedstock) were curtailed abruptly in February 2003, they have been able to procure enough gas in the market, combined with non-Maui arrangements in place, to operate their facilities at approximately 40% of capacity in 2003, an estimated 44% in 2004, and a forecast 15% in 2005 (based on Methanex third quarter 2004 interim report). Also, Ballance have been able to secure a 1-year supply contract for their full 7 PJ requirement from the May 2005 expiry of previous arrangements.

functioning market freed of the inflexibilities of the original Maui Contract. Transactions in the emergent gas market signal the need to either find more indigenous gas, import it or switch to an alternative fuel in order to satisfy demand. Recent anecdotal evidence indicates prices over $6/GJ for new supply contracts in some instances, compared to the previous Maui price which was in the range of $2 to $2.50/GJ.

In this report, gas prices are assumed to rise from a current average level of $4.50-$5/GJ by 4% a year to around $7.50/GJ by 2015. Price rises will be moderated from even higher levels by shedding of demand from those consumers who cannot afford to use higher cost gas, by the price of substitute fuels such as coal or fuel oil, and by the development of new discoveries. Ultimately, long-term gas prices will be capped by the import price, which in New Zealand's case means the price of LNG.

The recent responses of major gas users, such as the successful bidding from petrochemical manufacturers together with switching to the use of coal as fuel for Huntly, show the effects of rising prices and expectation of future shortage on consumers; and the important influence large-scale users exert in the small New Zealand gas market. The lower-value users are the first to cease bidding for gas and, where this leads to curtail of their output, there will be consequential negative effects on industrial output and a potential lowering of the country's export base.

This situation underscores one of the main difficulties with the small size of the New Zealand gas market. Without large consumers such as Methanex, and with the climatically-driven cyclicity in demand for thermal electricity, the economy may struggle to fully take up large tranches of new supply, such as that expected from the development of the Pohokura field. While the e3p gas-fired station will add a demand increment of around 20 PJ/year, this of itself does not justify the economic development of the Pohokura field. Also, whilst energy suppliers may wish to reserve developed gas for electricity and gas demand (especially during periods when the output of non-thermal energy is high and energy prices depressed) there may be circumstances when prices offered by non-energy users will be sufficient to secure them ongoing gas supplies.

In the short term, other demand shedding and fuel substitution possibilities are limited by the inflexibility of existing energy-consuming plant and the availability of substitute fuels. However, consumers are more able to respond to scarcity and rising price signals over the longer term. There is already evidence that some industrial gas users are planning to switch to coal.

Higher-value gas users such as reticulated gas retailers and electricity generators have been able to secure supplies and would seem to be adequately covered for a number of years, albeit at higher prices but with considerable ability to pass through price increases by way of higher tariffs. Their strategies for balancing gas entitlements with demand for their energy services will be a key factor in the evolution of the New Zealand thermal fuels market in the post-Maui era.

THE SUPPLY SIDE PERSPECTIVE

Table 1 shows published gas reserves as at January 2004. All these fields, at various stages of depletion or development, are in the Taranaki Basin. Reserves in the Pohokura field are not included, but have been stated to be 700PJ (proven plus probable). New Zealand thus had 2162 PJ of estimated recoverable reserves as at 1 January 2004.

At the peak annual production level of 242 PJ (set in 2001), these reserves represent just nine years of production. At the current production rate of about 150 PJ/year, they represent 14 years of consumption. Without Pohokura or Kupe, developed reserves represent about eight years of production at 150 PJ/year, underlining the importance of the timely development of these fields and the opportunity for immediate development of any further discoveries as their reserves are proven.

The indigenous gas scenario examines three gas supply cases:

- supply from developed fields
- supply from developed fields and those approaching development (Kupe and Pohokura)

Field	Reserves[1]			Production[2] 2002 PJ
	Ultimate Recoverable PJ	As at 1 January 2004 PJ	Gross Calorific Value[3] PJ/Mm^3	
Kaimiro/Ngatoro[4]	23	6	0.045	2.29
Kapuni[2]	1,100	343	0.025	24.18
Kupe	309	309		0.00
Maui[2]	3,825	539	0.041	121.99
McKee	210	75	0.041	6.83
Mangahewa	91	66	0.039	8.41
Piakau	7	0		0.00
Tariki/Ahuroa[2]	132	48	0.045	15.29
Waihapa/Ngaere	36	0	0.044	0.23
Rimu/Kauri[2]	81	78	0.042	1.85
TOTAL	5,812	1,462		180.07

1 Reserves are estimated as "proven and probable" or P50 by the field operators
2 Excludes LPG for Kapuni, Maui, Tariki/Ahuroa and Rimu/Kauri and also re-injection for Kapuni. The figures here differ from Table E.2a (MED Energy Data File on-line (January 2003)) in that own use, losses and flared are included here.
3 Gross calorific values are for the given production figures.
4 Includes information for Goldie well.

Table 1: New Zealand gas reserves. Source: MED Energy Data File January 2004.

- supply from all these fields, together with new discoveries.

Gas supply from known fields

Figure 2 illustrates the expected production of natural gas from developed fields overlaid with three projected demand profiles. Total production from Maui is taken to include all of the official proven plus probable ("2P") reserves tabulated in September 2004, and the model assumes further development of onshore Taranaki fields to provide for a small overall increase in production over the next few years. Estimated 2004 demand is based on information concerning consumption in both electricity generation and petrochemicals.

The supply situation for 2005 and 2006 can best be described as "tight", with little left over for other uses once reticulated consumption and the two existing GCC electricity generation plants are accounted for. Post-ERR Maui gas will be required by 2005, excluding all petrochemical consumption. While Methanex is believed to have around 20 PJ secured for use in 2005, any additional gas for petrochemicals in 2005 and 2006 is essentially reliant on gas from the Maui above ERR becoming available. If this source is secure, up to 75 PJ may be available for limited petrochemicals manufacture in 2005 and 2006.

By 2007, when Genesis Energy's e3p GCC station at Huntly is scheduled to be commissioned, reserves from Pohokura and Kupe will probably be required to meet expected consumption levels.

Figure 3 illustrates the expected annual supply of natural gas, including Pohokura and Kupe, overlaid with the three projected demand profiles but without provision for further discoveries.

The Pohokura field is expected to come on stream in late 2006 with an initial production capacity of about 73 PJ a year in 2007. The smaller Kupe field is expected to commence development in the second half of 2005 with first gas delivery in 2007 at about 20 PJ a year.

The development of the Pohokura and Kupe fields and the commissioning of the e3p GCC station in 2007 will provide much needed "breathing space" for gas and electricity supply, respectively. However, there are some significant risks in terms of both deliverable

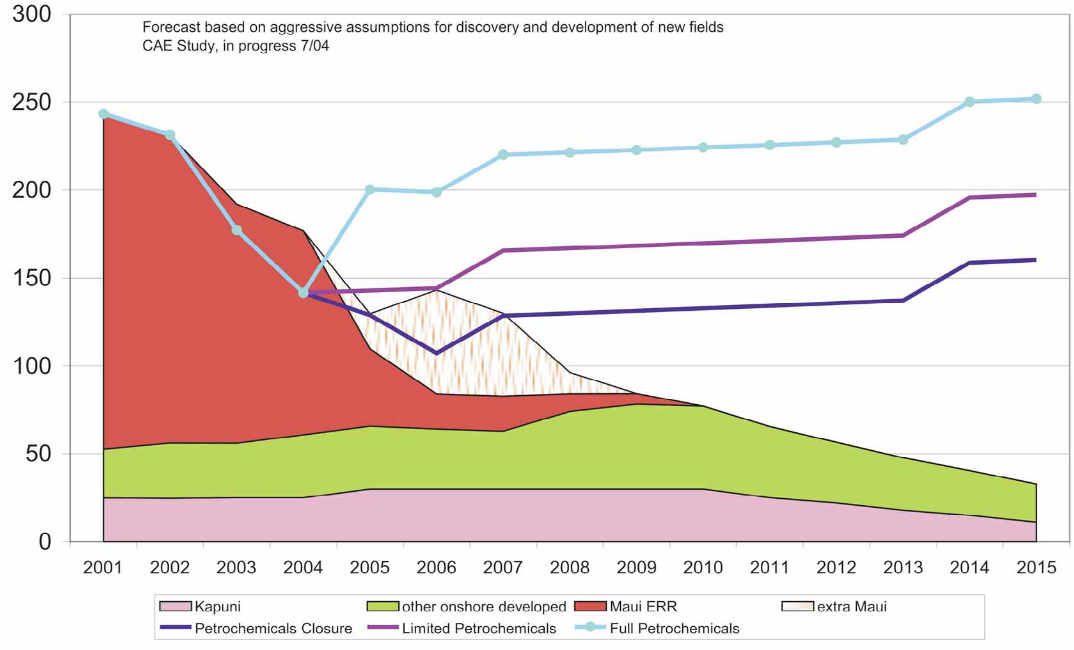


Figure 2: Supply capacity of developed gas fields.

gas quantities and timing of delivery, increasing over time. Slippage in the commissioning of the Pohokura field would create an undesirably tight natural gas supply situation, even more so if assumptions made here as to the availability of a Maui tranche above that deemed ERR do not fully materialise.

Projected production rates for Pohokura suggest that there will be gas available beyond that required for reticulation and GCC electricity generation until early in the next decade, a situation that could see some gas become available for use at the existing Huntly power station or for petrochemicals, provided prices are acceptable for those uses and the plant still exist in working order. The alternative is for this "surplus" gas to be banked. This is unlikely to be in the interests of economic field

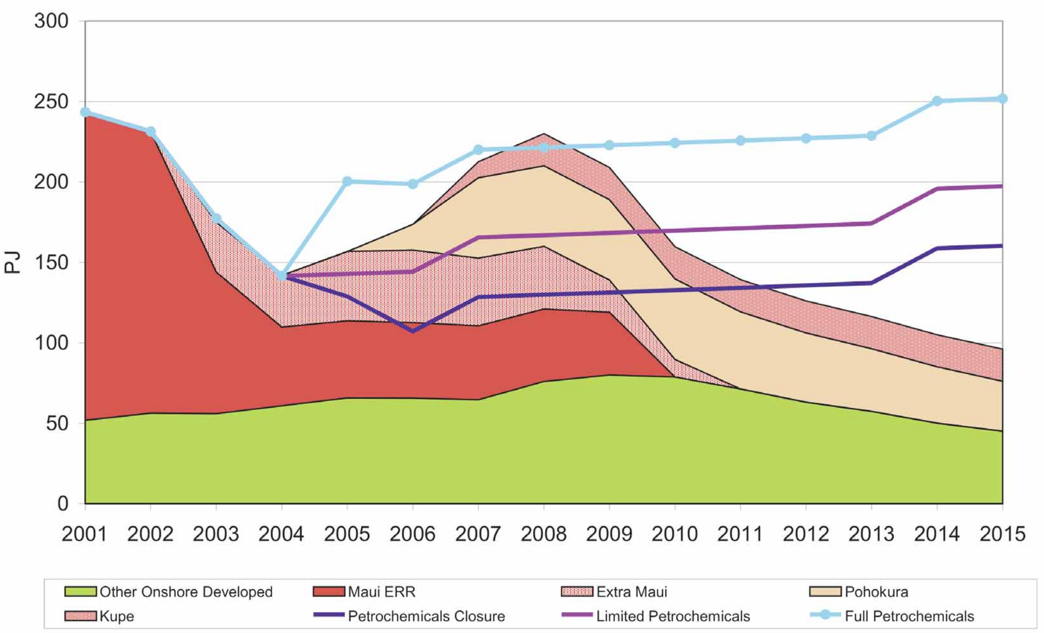


Figure 3: Supply capacity of developed gas fields plus Kupe and Pohokura.

operations nor of the income requirements of the field owners, and the Pohokura contracts agreed during 2004 are likely to include at least some "take or pay" provisions.

Assuming extra Maui reserves and expansion of onshore fields are together capable of meeting the assumed offtake, and the timely development of both Pohokura and Kupe, new undiscovered reserves will not necessarily be called for until early in the next decade, particularly if petrochemical consumption were to cease entirely.

The potential for new discoveries

Exploration investment in New Zealand has been recovering from a depressed state in the 1990s, but has not yet reached the level needed to provide for sufficient discoveries to sustain New Zealand's reserves inventory. Because of low Maui gas prices, oil has until recently been the main target for exploration with gas discoveries an often commercially disappointing by-product. Gas is now recognised as valuable in its own right with the strong upward pressure on gas price expectations as Maui depletes.

As prices have been struck for gas tranches from Pohokura, Kupe and Maui tail gas, incentives for more resolute gas exploration activity have dramatically improved.

Figure 4 shows that the thermal fuels gap could be met through a plausible scenario of rising levels of petroleum exploration that resulted in a new sustained level of gas discovery, expansion of the gas reserves inventory, and development of new fields.

Due to the lead time required to bring new discoveries to market, some new discoveries will need to be made well before 2009. While onshore Taranaki discoveries may be able to be brought into production within about three years, offshore Taranaki discoveries can be assumed to take around five years to bring into production, or 10 years in new production theatres.

This highlights the urgency to make new discoveries within the next year or two, not only for security of supply but also to prove that the New Zealand resource has the potential to satisfy local demand. In fact, discovery rates in excess of consumption rates are required to improve the New Zealand reserves inventory situation.

Unlike in many countries where natural gas has been discovered and awaits markets to fund development, New Zealand does not have such a luxury. While higher exploration levels will

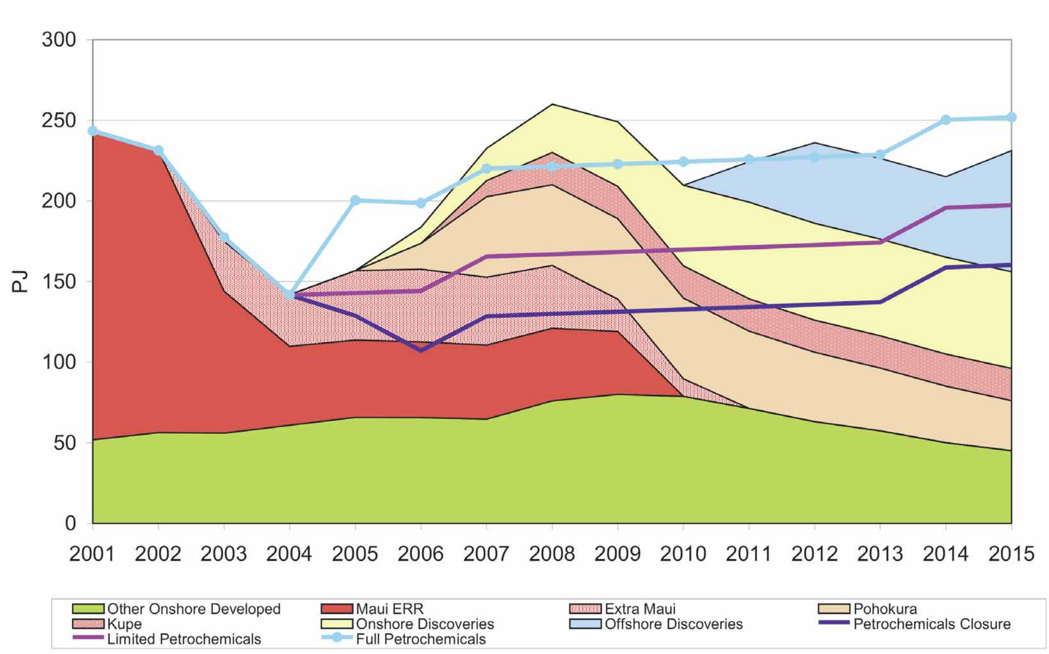


Figure 4: Supply capacity of developed gas fields, those nearly ready for development, discovered reserves and possible new discoveries.

increase the prospects of more commercial discoveries of oil and gas, any discoveries will need to be brought to market as soon as possible. This "just-in-time" situation presents its own risks for energy consumers and the economy.

Given well-conceived and adequately funded effort, the fundamentals for further discoveries are strong. New Zealand has small gas reserves but an enormous unrealised resource potential, especially offshore.

Figure 5 shows the classification of petroleum resources in relation to the business processes relative to indigenous natural gas. The imperative for New Zealand is to foster investment in the exploration and discovery process (black arrow) to move undiscovered potential into discovered resources.

The grey arrow represents production, coincident with the delivery of gas from proven developed fields to purchasers who may either on-sell it, processed or raw, or convert it into electricity or petrochemical commodities such as methanol and urea.

When during the Maui era the reserves base was large relative to production, then there was little or no commercial merit in adding to it through investment in either appraisal and development (white arrows) or through exploration and discovery (black arrow), except that gas is also produced and indeed discovered incidentally to production of and exploration for oil. The fact that much of the known natural gas in the world has been discovered as a consequence of oil exploration accounts for its historically discounted value relative to its utility compared to most other energy sources.

Under an aggressive exploration climate, there are realistic prospects for restoring the country's reserves inventory and returning to a situation of reliable gas supplies. Onshore production for a period could be double current production levels, and offshore production similar to that which the Maui field produced at its peak. In aggregate, production levels could be similar to the 200-250 PJ/year achieved in the later part of the Maui era. These production levels would allow the petrochemicals industries to operate on a similar scale to that held during the Maui era, if gas prices are acceptable, and to open up the opportunity for further increments of gas-fired electricity generation capacity if new capacity is not provided through alternative generation sources such as coal or renewables.

While not all are prerequisites, some combination of the following factors would be

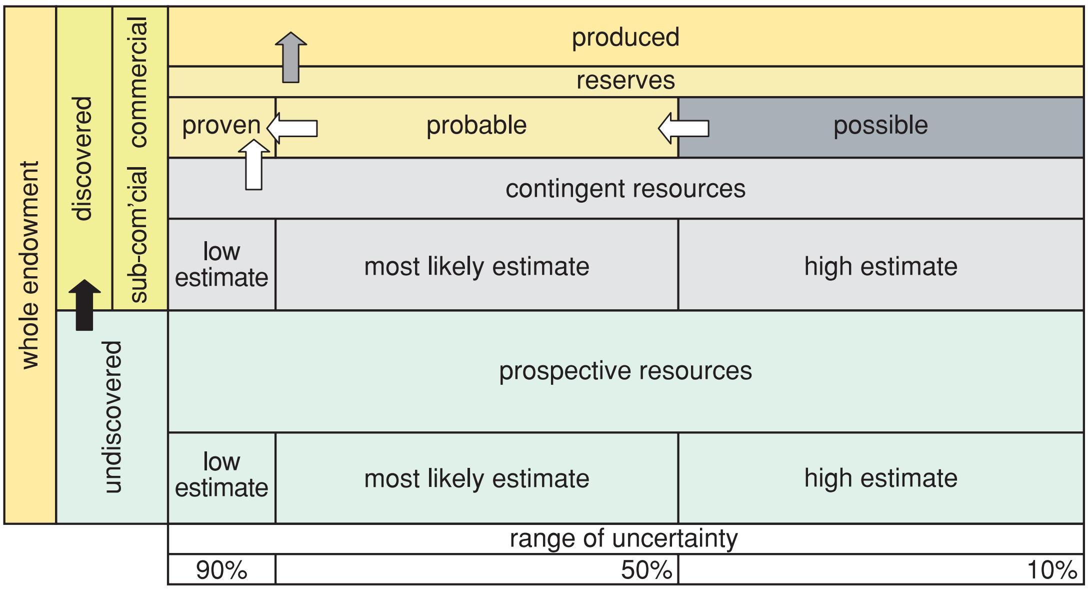


Figure 5: Classification of petroleum resources. Arrows show the enhancement of certainty that results from exploration and development. Grey arrow = production; white arrows = appraisal and development; black arrow = exploration and discovery.

required for such a scenario to eventuate.

- Continuing exploration success, especially further oil discoveries.
- High prices bid for tranches of gas from fields currently being developed. Pohokura and Kupe gas are by far the most volumetrically important of these, but smaller tranches from onshore Taranaki developments could play a role in price setting.
- Strong fundamentals for the global E&P sector with capital in-flows to encourage investment in high-risk, long lead-time exploration prospects in under-explored New Zealand prospects. Almost of necessity, this would require investment in New Zealand by top-ranked exploration companies who do not currently operate here.
- Continuing development of enabling technologies and market dynamics that would improve the prospects for developing some of New Zealand's stranded potential gas resources.

New Zealand has huge potential to convert its geological resource endowment into reserves. The alternative is to supplement a dwindling indigenous natural gas supply with thermal fuels from other sources.

the LNG scenario

If natural gas use in New Zealand is to continue at levels of 150 PJ/year or more, and if the indigenous resource base cannot be maintained through discoveries to match the rate of consumption, then alternative supplies of gas will be needed to make up the shortfall. Importing natural gas through pipelines is not a possibility for New Zealand, as is the case for many gas-importing countries. If new indigenous gas resources are not discovered, the most discussed alternative to remedy shortfalls of natural gas supply is to import liquefied natural gas (LNG).

This does not imply that other fuels, notably coal, are not suitable alternatives to gas for thermal fuel supply in New Zealand. These fuels are dealt with later in this report.

THE NATURE OF LNG TRADING

The LNG supply chain

LNG is natural gas that has been cooled to minus 160^{o}C at atmospheric pressure, allowing the gas to be stored at 1/610th of its original volume, and more economically transported from its source to regasification facilities at or near the locations of consumption. As a rule of thumb, LNG becomes a cheaper mode of moving natural gas than pipelines once the distance between supply and demand points exceeds about 2000 km.

The LNG supply chain comprises:

- the source gas field
- a liquefaction plant usually consisting of a number of liquefaction trains
- tankers transporting the LNG from the liquefaction plant
- a receiving terminal which consists of storage and regasification facilities.

Because it is not economic to pump LNG for any distance, it needs to be stored and regasified close to its unloading point. Regasification can be carried out on a land-based LNG regasification plant near a tanker port, an offshore LNG regasification station (which provides a mooring but not LNG storage), or an LNG regasification vessel (RV) with the regasification unit located on the vessel and the vessel itself serving as the storage facility. Regasified LNG can then be piped through conventional transmission and distribution systems to consumers.

LNG is a large-scale, capital-intensive industry involving investment in liquefaction plants, tankers and receiving terminals, so that LNG projects require large gas reserves and certain markets in order to proceed. Increasing plant size is used to exploit economies of scale to reduce costs. This is particularly true for liquefaction plants but also applies to the increasing size of tankers and receiving terminals. Liquefaction train capacity generally exceeds 1.5 million tonnes a year (about 80 PJ), with most liquefaction plants having multiple trains. Storage and regasification plant capacities invariably exceed 200 million litres (about 5 PJ), with five times this size being common. Upscaling and maximum utilisation is of the essence for exploiting economies of scale and reducing unit cost, and potential developments need to be considered in this context.

A typical standard sized tanker of 135,000 - 160,000 m^3 costs around US$150 million to build. The LNG tanker fleet is growing rapidly, from 128 at the beginning of 2002 to 154 as at the end of 2003, with the fleet size projected by the IEA to reach 500 tankers by 2030. Charter rates are generally not widely publicised but are in the range of US$60,000 - 100,000 per day for medium and long-term charters. Shipping costs are falling, mainly from improved construction processes and the economies of scale of increasingly larger tankers. Spot charter rates are dependent on market conditions, but rates of US$150,000 per day are not unknown.

World LNG trade

About one quarter of world natural gas production is traded, comprising 17.4% pipeline natural gas and 6.5% LNG. LNG consumption increased by 6.2% a year in the decade between 1992 and 2002, and a similar rate of growth is projected for the next few years. In 2003, LNG sales increased by 12% while overall natural gas consumption grew by only 2%. Thus, while the LNG is a large and rapidly expanding industry, it comprises only a small percentage of the overall natural gas industry.

The current state of world LNG markets owes much of its existence to the development of the East Asia markets since 1969, with Japan, South Korea and Taiwan currently taking around 70% of the world's LNG imports. Each country is essentially completely dependent on LNG for its natural gas supplies, with energy security more important than price. Government involvement to facilitate the importation of LNG and development of the domestic consumption base, together with rapid economic and industrial development in all three countries, have meant that LNG imports have grown rapidly.

Further market expansion is expected to come from the large and strongly growing economies of China and India where natural gas is projected to gain an increasing share of the direct use, industrial and power generation markets. In the USA, increasing LNG imports seem likely to be needed to meet expanding gas consumption as pipeline supplies from within continental North America are expected to remain relatively static and could even decline.

LNG contracts and pricing

World LNG markets can be divided into three regions which currently operate fairly independently: Asia, Europe and North America (Figure 6). Historically, buyers have had to enter into long-term supply and purchase agreements (SPAs) of 15 years or longer before projects proceeded. Natural gas prices, and especially LNG prices, are generally linked to the price of crude oil using agreed formulae (Figure 7).

The shifts in pricing formulae depicted in Figure 7 represent changing market conditions. How market conditions will evolve is uncertain but they currently appear to favour buyers of LNG. Rapidly growing demand is being exceeded by even more rapidly expanding supply. For the first time in the industry's short history, there is uncontracted liquefaction and shipping capacity coming onto the market.

Growth in demand, however, is expected to be underpinned by the strongly growing and large economies of China and India. There is also a view that rapidly expanding USA imports required to meet growing natural gas demand will act to underpin both demand and prices.

In a global context, therefore, the new pricing formula shown in Figure 7 may well illustrate the best that New Zealand could achieve due

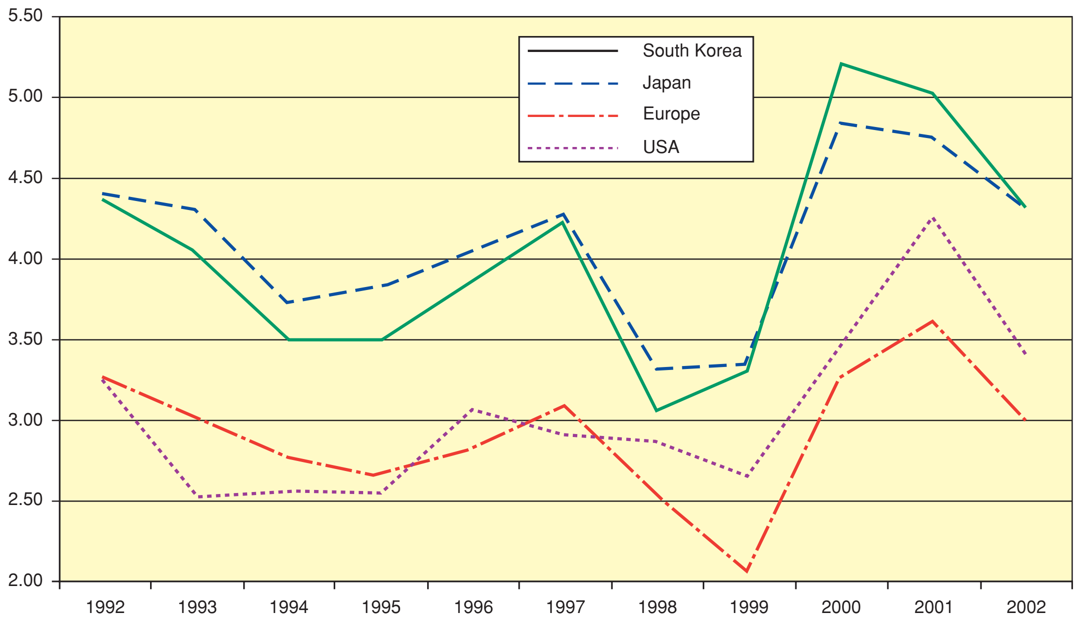


Figure 6: Regional LNG import prices. Data Source: IEA Energy Prices and Taxes.

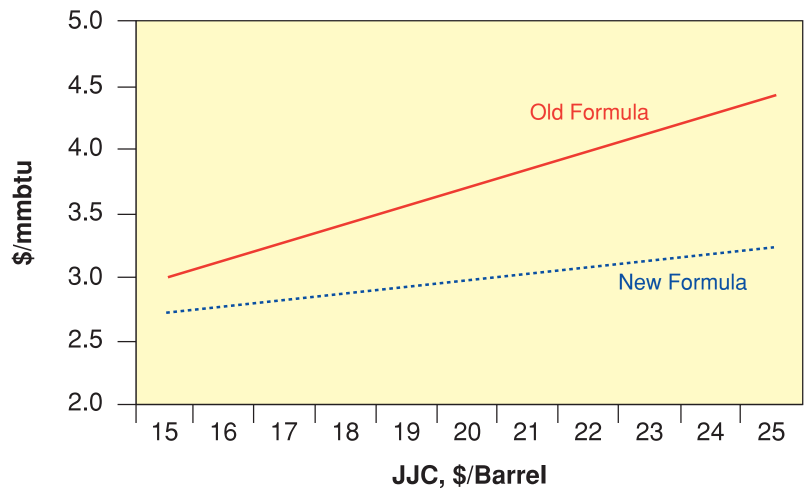


Figure 7: Comparison of "new" and "old" price formulae for LNG based on a crude oil price known as the Japanese Crude Cocktail (JCC) formula.

to our small market.

The Asian markets of Japan, Korea and Taiwan have dominated world LNG trade for over 30 years. Asian LNG prices have often been 20-50% higher than in Europe or the USA, partly because of the link to crude oil prices which tend to be higher in Asia than elsewhere.

China's entry into LNG imports has recently set a precedent for lower Asian prices. Given the potential size of the Chinese and Indian markets, these buyers have the potential to influence the whole dynamics of the industry.

As long-term contracts expire, Asian buyers will seek contracts that are more flexible and more attuned to market pricing, with some trade-offs in energy security. The historical dominance of long-term contracts will diminish, to be progressively replaced by a greater diversity of SPAs along the whole supply chain. The regional differentiation in prices may narrow to the advantage of Asian buyers. On the other hand, expansion of the North American market in response to gas market growth and constraints on domestic pipeline gas supplies may play a role in underpinning world LNG prices.

Although the historical linkage to oil prices may well weaken, it is not expected to be entirely severed. Overall, trade in LNG will become more dynamic, although not to the extent of world oil markets or North American pipeline gas markets, and prices seem likely to fall.

Assuming the 'new formula' as shown in Figure 7, FoB prices for LNG are indicated at US$3.30/GJ[2] at US$30/barrel and US$4.00/GJ at US$45/barrel of oil.

On the supply side, known gas reserves are adequate for about 67 years of consumption. Upstream developments in Iran, the Middle East, Russia, and South America in particular will influence LNG supplies. A likely source for LNG imports into New Zealand is Indonesia or Australia.

LNG IN THE NEW ZEALAND CONTEXT

Project scale

The starting point for considering LNG importation to New Zealand is agreement on project scale. Our analysis suggests a maximum additional annual gas requirement of perhaps up to 80 PJ, depending on the extent of demand shedding and the timing of an LNG project. Coincidentally, 80 PJ/year is about the amount that a typical LNG tanker would be able to deliver on a full charter basis, assuming a 15 day turnaround schedule.

This amount, whilst large compared to the current size of the New Zealand gas market of about 150 PJ/year, is only about 0.2% of current world LNG trade and at the lower end of the minimum economic scale. This poses a

[2] LNG prices are usually denominated in US$ per mmBtu, and for this report have been converted at 1 million Btu to 1.0551GJ. Prices can be either FoB (free-on-board; more common) or ex-ship (delivered).

likely disadvantage when considering LNG importation into New Zealand.

Infrastructure requirements and costs

The New Zealand-based component of the LNG supply chain is a regasification facility and associated infrastructure, the options for which are:

- A land-based LNG regasification near a tanker port.
- An LNG RV (regasification vessel) with the regasification unit located on the vessel and the vessel itself serving as the storage facility
- An offshore LNG regasification facility. This option is not considered economically viable and is not considered further.

Port facilities

The first infrastructure requirement for an LNG scenario is a suitable port facility for either an LNG tanker or a permanently moored LNG RV. The scenario examined in this study assumes that LNG will be supplied using a 145,000 m^3 LNG tanker, and a mooring or berthing point must be able to receive a vessel of this size. The port configuration for either a tanker or an LNG RV is much the same.

Possible location options for a land-based plant include:

- Upgrade of Port Taranaki (WestGate).
- Upgrade of Marsden Point and lay a new gas pipeline to Auckland.

The land-based option

A conventional land-based receiving and storage terminal and regasification plant for a facility sized to supply 80 PJ/y is estimated to cost approximately US$280 million plus infrastructure costs of between US$60m and US$90m depending on location and specific site factors. Such a facility would supply an annual quantity of 1.56 million tonnes per year LNG, with a maximum daily delivery of 5.1 kt. Annual operating costs are estimated at US$16m/y.

These are fixed facilities that have no alternative use. The high capital costs of such an installation would need a high level of utilisation over a considerable period of time to make the project economic. Unit costs required to service the investment escalate rapidly if the plant is not fully utilised.

An investor would also need to be confident that the asset would not be stranded by cheaper alternative thermal fuels such as indigenous natural gas or coal. To realise a land-based scheme, a long-term take-or-pay SPA would probably be required. The implications of such an arrangement are discussed on page 23.

The regasification vessel option

LNG regasification vessels are an emerging application of LNG storage and regasification. The appeal of this approach is that it removes some of the costs and inflexibility associated with a land-based plant. Although not functionally complicated, its novelty in terms of both technology application and LNG delivery clearly opens up a number of risks that have not yet been tested in the market. Innovative and flexible contracts, certainly as far as the LNG industry is concerned, would be needed to take advantage of this much more flexible option. It is unclear whether and how quickly the RV application will develop, but the first ships are close to launch.

The cost of RV implementation is lower than the more conventional land-based receiving and regasification terminal option. An estimated cost of US$200 million for a regasification vessel capable of supplying the same quantities as a land-based facility represents the minimum capital cost for the LNG RV option and can be broken down to US$150m for the tanker and US$50m for the on-ship regasification equipment.

Whilst storage volumes will be less than the equivalent land-based facilities, opportunities in New Zealand could include permanent mooring to the Maui B platform (although this has not been examined). Ancillary infrastructure costs and working capital of US$30 million take the estimated capital commitment to around US$230m, some US$110m less than for the land-base scheme. Annual estimated operating costs are similar at approximately US$15.6m/y.

Very importantly, the RV option reduces the possibility of a stranded asset should the demand for LNG fall below projected levels or other circumstances change. Using RVs also opens up the possibility of LNG being used to serve temporary shortfalls in natural gas supply on a bridging basis, with both LNG and vessels being contracted more or less on a spot basis. On the negative side, the short-term/spot LNG market is not nearly as well developed as it is for oil trade and, although increasing, currently comprises only about 5-10% of total volume. The price of spot cargos will be more volatile than for a long-term contract.

Another consideration is that New Zealand thermal fuel demand is counter-seasonal to the much larger northern hemisphere LNG market. It would not be hard to imagine that co-operative and mutually beneficial contract arrangements for both capacity and LNG delivery along the whole supply chain could be made with Asian importers. This becomes increasingly possible if and when the nascent RV system gains critical mass in world LNG markets.

However, this does not mean that the LNG RV option could provide a silver bullet to solve New Zealand's dry year hydro capacity problems. While there is potential for flexibility, a great deal of investigation is required to asses the commercial viability of short-term LNG importation.

LNG price

Excluding infrastructure costs, the price components of LNG supply are the ex regasification plant (FoB) gas price, the shipping cost, and the storage and regasification cost. Of these, only the last can be controlled by the gas buyer. Project economics are set out below.

In addition, two other key variables will also impact on the eventual ex regasification plant price; the oil price, to which LNG prices are linked by agreed formulae (Figure 7), and the exchange rate. For the purposes of this report, project economics are based on an oil price of US$30/bbl and a NZ/US exchange rate of 55c/US$. Table 3 gives a range of outcomes for different oil price and exchange rate assumptions.

Project economics

Based on the study cost estimates and the assumptions set out below, project economic analyses were performed for both the land-based and RV options. The processing tariff was chosen as the key reporting variable as an indication of a likely tolling fee for a New Zealand regasification facility. This tariff was varied and plotted against the required Internal Rate of Return (IRR) to achieve a zero net present value (NPV) for each process (Figure 8).

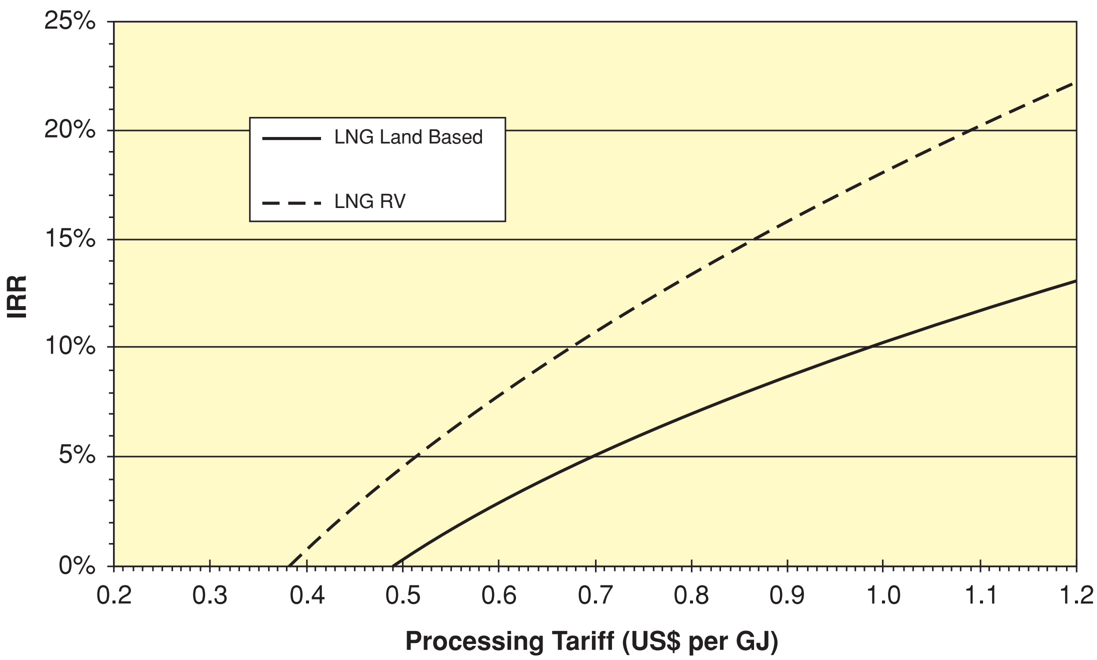


Figure 8: Comparison of land-based LNG and an LNG RV showing IRR as a function of processing tariff.

The assumptions made are:

- plant life of 15 years
- straight line depreciation, with no salvage value after 15 years
- working capital is the cost of LNG to fill the storage tanks
- working capital is injected at year 0 and recovered in year 15
- 50% production in year 1, and 100% afterwards
- production to begin after four years for a land-based plant and two years for an LNG RV.

This indicates that a land-based scheme would need to earn a storage and regasification tariff of approximately US$1.15/GJ to justify the investment in facilities and infrastructure. From this an overall LNG price is arrived at, as shown in Table 2. Assuming that the LNG can be obtained FoB for US$3.30/GJ (prevailing oil price of US$30/barrel), and with a shipping tariff of around US$0.33/GJ, a LPG gas cost of NZ$8.70/GJ (NZ$1 = US$0.55) is arrived at before the natural gas enters the transmission and distribution system.

A scheme employing a regasification vessel, effectively using a tanker as a storage and regasification plant, would need a regasification tariff in the range US$0.80/GJ, to achieve an IRR of 10-15%. Assuming again that the LNG can be obtained fob for US$3.30/GJ, and with a shipping tariff of around US$0.33/GJ, a gas cost of NZ$8.05/GJ is arrived at before the gas enters the transmission and distribution system.

Table 3 extends the analysis for a range of oil price and exchange rate assumptions.

Cost component		**Conventional land-based**	**Regasification vessel**
LNG FoB	US$/GJ	US$3.30	
Shipping		US$0.33	
Storage/regasification tariff @ 12.5% IRR		US$1.15	US$0.80
Total		US$4.78	US$4.43
	NZ$ @ 0.55	NZ$8.70	NZ$8.05

Table 2: LNG price components comparing conventional land-based and regasification vessel options.

Oil price US$/bbl	LNG price US$/GJ	LNG price NZ$/GJ @45c/US$1	LNG price NZ$/GJ @55c/US$1	LNG price NZ$/GJ @65c/US$1
20	3.00	9.48	7.75	6.56
25	3.25	10.00	8.19	6.93
30	3.50	10.53	8.70	7.29
35	3.75	11.06	9.05	7.66
40	4.00	11.58	9.48	8.02
45	4.25	12.11	9.91	8.38
50	4.50	12.64	10.34	8.75

Table 3: Forecast LNG price as a function of oil price and exchange rate.

alternative thermal fuels

New Zealand needs thermal energy solutions that can balance energy security against higher costs as well as contribute to the need for the flexibility of energy delivery that the Maui field allowed. In particular, New Zealand has to find ways of better dealing with the seasonal problems associated with a hydro-dominated electricity supply system that is subject to uncertain availability and is most constrained when demand is highest.

The potential of the indigenous natural gas sector, whose development has been held back by the dominance of the Maui field and Maui Contract, needs to be given an opportunity to be realised. Alternatives should also be considered, at least until this option is foreclosed.

There is a range of alternative thermal energy supply solutions, which may be used on their own or in combination, either sustained or occasional, and either as permanent or "bridge" solutions. In addition to indigenous gas and LNG imports, these alternatives could include:

- increased mining of indigenous coal or importing of coal for burning in new power stations and for direct use
- importing compressed natural gas (CNG)
- importing naphtha or liquid petroleum gas (LPG) for processing into SNG (synthetic/substitute natural gas) or burning in existing power stations
- coal seam gas (CSG), also known as coal bed methane (CBM)

Of these, importing naphtha or LPG, at prices of around US$6-7/GJ before shipping, is too expensive. While both, and LPG especially, could increase market share in some niche applications such as extending beyond domestic use in the South Island or for commercial cooking, we eliminate both as options to fill any gas gap. Similarly, the use of diesel or fuel oils to provide electricity or fire industrial plants would also be expensive and is not further considered here.

COAL

Coal has often been considered the "backstop" fuel for New Zealand's electricity needs. Now, with a gas shortage and higher gas prices in the post-Maui era, coal has the potential to reassert itself in the thermal fuels markets generally, for both electricity generation and industrial use. Along with indigenous natural gas, which is reliant on new discoveries being made soon, coal is the other apparent option for thermal fuel supply in New Zealand because of the extent of the proven indigenous resource and its opportunity to improve fuel diversity. Coal already supplies over 9% of our primary energy supply.

One important advantage of coal is that it can be stockpiled, which gives it the potential to replace the swing capacity of the Maui field. For electricity generation, this flexibility makes coal suitable for peak as well as base-load use. While the gas sector in New Zealand has so far been based entirely on indigenous supply, coal is freely traded and import prices, which will be on an export or import parity basis plus any carbon tax that may be implemented, may not only be lower but less volatile. This tradability also means that it can be used as a "bridge" fuel during shortfalls of indigenous gas supply, or even coal supply. This is already occurring at the Huntly power station.

Capacity of New Zealand coal resources

Economically recoverable resources are estimated at 150,000 PJ, or about 75 times current gas reserves, although New Zealand's coal resource inventory[3] is effectively 15 years out of date. About 20% of estimated recoverable resources are the higher grade bituminous and sub-bituminous coals, which account for almost all current production of about 130 PJ/year. About half of this is exported. At this rate of production, New Zealand has coal resources to last 230 years, disregarding the enormous lignite resource in the Southland/Otago regions.

[3] JM Barry and others 1994. Coal resources of New Zealand. Resource information report 16. Ministry of Commerce.

However, the ability to deliver coal to points of consumption is dependent on a supply chain being in place, including:

- operating mines
- reliable production capacity or inventory stockpile of a suitable grade and quantity
- transportation arrangements.

The inability to supply domestic coal to the Huntly power station during the electricity crisis of 2003 exposed the difficulties of substantially increasing coal supply at very short notice outside of contractual arrangements, and coal had to be imported. Rather than indicating any weakness in the New Zealand coal supply chain, it shows again the reliance there has been on the swing capacity of the Maui field to cover thermal fuel requirements in dry years. Coal supply requires higher levels of market commitment.

About 70 PJ of coal was consumed in New Zealand in 2003, and the dual-fuel capability of the Huntly power station results in a total capacity to consume over 100 PJ/year from existing plant. Export markets have not so far been competing for the same resources, being generally for a higher grade of coal for specialist metallurgical uses than that required for most demand in New Zealand, although exports of thermal coal are increasing.

Current coal mines are located in the Waikato (servicing principally New Zealand Steel's Glenbrook mill as well as the Huntly power station and several major industrial customers), Otago/Southland (servicing mainly local industrial and domestic markets) and on the West Coast (servicing mainly export markets).

The output of Waikato mines was about 38 PJ in 2003. Principal miner Solid Energy Ltd has reported reserves of 320 PJ in the Waikato that would be economic to develop at prices of $3 to $3.50/GJ. While these reserves are modest in relation to consumption by the Huntly power station and other existing North Island coal consumers, including the Glenbrook steel mill, there are extensive other resources in the region which require market certainty to convert to reserves.

The role of Huntly

Apart from co-generation use, New Zealand's only coal-fired power station is Genesis Power's 1000 MW dual coal/gas station at Huntly, which can supply up to 20% of New Zealand's electricity requirements. Its large size, and capacity to switch fuels and set electricity prices, mean that the station plays an important role in thermal fuels and electricity markets.

Since the Maui re-determination, and the consequential gas shortage and higher prices, Huntly has generated entirely on coal. This is in contrast to previous years, when Huntly was generally gas-fired at lower prices than coal.

Exacerbated by the hydro shortage in the winter of 2003, Huntly used some 34 PJ of coal in the year ending March 2004. This compares with around 19 PJ in the previous year and less than 10 PJ/year in some recent years prior to that. Gas prices have risen to the extent that Huntly, generating on coal at around 35% thermal efficiency, has generally this year bid ahead of gas-fired generation at Taranaki CC or Otahuhu B, both about 50% thermally more efficient than Huntly.

New coal mine opportunities

Almost 6000 PJ of known coal resources in the Waikato region require further economic viability analysis, but would presumably be available at higher price levels. It seems likely that coal from new mines in the Waikato would find willing buyers at prices at or above the $3 to $3.50/GJ level, with a new power project the likely key driver. Solid Energy estimate that at a power price of 7c to 8c/kWh (excluding any carbon tax), a 500 MW power station supplied with Waikato (or conceivably imported) coal could cover a fuel cost of between $2.60 and $3.90/GJ depending on its location relative to the upper North Island electricity loads. Mines to supply such a power station would require an additional annual output of over 1.5 million tonnes, compared to the 2002 output of all mines in the Waikato of 2.3 million tonnes.

There are extensive coal resources in other regions, particularly Taranaki, the West Coast, Otago and Southland. However, there are some issues regarding location with respect to energy loads and additional costs for transportation, either as coal to power stations and other users, or as electricity if generated near the coalfields.

The critical path to commissioning new mines would appear to be dominated by market uncertainty, economic constraints and consenting processes which provide the opportunity for a wide variety of interests to be heard. Mining and increased coal consumption seem likely to draw objections from several environmental angles, more so in the Waikato than in the South Island or Taranaki.

Technological advances in the performance of coal-fuelled electricity generation are resulting in improved thermal efficiency and reduced greenhouse gas emissions, and new capital investments in New Zealand are likely to take advantage of these features. Solid Energy has established the commercial viability of a coal-fired 150 MW power station in the Buller region, where the company has substantial reserves and mining competency. While a larger power station would generate output in excess of expected regional demand, a thermal power station in Buller or anywhere else in the South Island provides the South Island with much needed fuel diversity in electricity generation, thereby increasing security of supply in dry years.

Under normal hydro flow, the abundance and price-competitiveness of hydroelectricity east of the South Island ranges weakens the commercial viability of coal-fired generation close to the voluminous and accessible Southland lignite resource base.

In the longer term, the extensive low-rank coal resources of the south-eastern South Island will almost certainly be called upon as more convenient energy sources are depleted and new feedstocks are sought. The lignites offer significant advantages over other coal types for conversion to hydrogen and liquid fuels.

COMPRESSED NATURAL GAS (CNG)

New Zealand has considerable experience in the small-scale supply and use of CNG that was developed as an alternative fuels solution following the oil crises of 1973 and 1979. CNG use in motor vehicles was subsidised and CNG usage peaked in 1985 at 5.85 PJ. With the removal of subsidies, motor vehicle conversions and consequential use of CNG declined rapidly. The industry is now all but extinct and much of New Zealand's CNG expertise and infrastructure has been lost. However, given this history, the production, delivery and handling of CNG would not likely present major technological challenges.

The greatest challenge for large scale CNG supply lies in the shipping segment of the supply chain. Unlike LNG, where less than 20% of the capital commitment is in the shipping segment, it is estimated that this is around 80-90% for CNG. The indicative capacity of CNG tankers is around 0.7 PJ, around a quarter of that of standard LNG tankers. While more storage volume is required for the same energy amount of CNG due to its lower density compared to LNG, CNG processing is technically simpler and therefore less expensive.

In contrast to LNG, the supply chain components of CNG can be applied and are economic on a smaller scale and are also more modular. While economies-of-scale may exist within the economic range for CNG, these seem likely to be less severe than for LNG.

Our preliminary analysis for the New Zealand segment of a CNG import scheme (the receiving, storage and decompression stages) uses the same methodology as for the LNG investigation. To facilitate comparison with the importation of LNG, an import level of 80 PJ has again been assumed. The following very approximate costing for supply of CNG to New Zealand indicates that potential per unit costs are similar to those for the LNG regasification vessel option.

Gas cost (on ship)	US$1/GJ
Shipping	US$2/GJ
NZ storage, etc	US$1/GJ
Total	US$4/GJ

However, the information base for the assessment of a CNG scheme is much weaker than for an LNG scheme, primarily because there has yet to be any commercial applications of large scale CNG production, shipping and importation. There is no established international market for CNG nor for the tankers, the most capital intensive, least proven and most important component of the supply chain. A target of around 2010 for the first commercial application has been suggested.

While these issues should not preclude a positive outcome, there are obvious risks with being a first mover in a small and thin market. Further investigation is suggested to determine the potential of imported CNG to fill any gas supply gap in the New Zealand thermal fuels market.

COAL SEAM GAS

A thermal energy resource associated with coalfields is coal-seam gas, which has been developed to an increasing extent overseas, notably in parts of the USA and in eastern Australia. Until fairly recently, development of coal-seam gas had been limited to coal deposits that are higher rank than most New Zealand resources. In the late 1990s, successful development of coal-seam gas from low-rank coals in the Powder River Basin in Wyoming led to the realisation that, in favourable circumstances, similar coal deposits might yield commercial gas flows elsewhere.

Investigation of the potential of sub-bituminous coals in New Zealand dates back to the late 1980s at Ohai in Southland, and most New Zealand coal resources are currently under investigation for coal-seam gas potential. It is too early to determine the potential of this resource.

thermal fuel markets and economic impacts in the post-Maui era

THERMAL FUEL MARKET CONTEXT

The New Zealand thermal fuels market is characterised by its small size and lack of diversity consequent on dominance by the Maui field. Delivery of energy to New Zealand consumers is achieved through a handful of firms who typically own facilities for generating or processing, aggregating, and contracting for the transmission and distribution of energy in its various forms to consumers. Barriers to entry to bring in new supply are difficult, not because of regulatory barriers, but because of the small size of the New Zealand market which creates its own element of risk.

These factors, amongst others, underscore the peculiar features of the New Zealand energy and thermal fuels markets that impacts on fuels choices and supply arrangements. Firms compete with each other both for energy supplies (both from thermal and other sources) and for customers, seeking to minimise cost for the one and maximise revenue from the other in order to generate the highest possible profit. Successful business strategies create a virtuous circle around a strong balance sheet with lower-cost financing and (if listed) a premium earnings multiple to share price. Conversely, a misguided business strategy can lead to rapid degradation of an energy company's standing, as for example struck some participants in 2001 when wholesale electricity prices exceeded retail prices over a period, creating negative margins.

The status quo for energy supply in New Zealand remains tuned to the Maui era, which, as we have described, was characterised by an inventory of proven developed natural gas reserves that were large relative to the rate of production. Although there has been considerable reform and market-driven adjustment "downstream" of the producing fields, giving the appearance of a vibrant and modern energy market, the effects of the Maui Contract have remained a dominant constraint on the behaviour of the major firms in New Zealand's energy market. Successful firms have tailored their business strategies around their particular exposure to the Maui Contract. The key features of the contract framework were:

- take-or-pay provisions that disincentivised "banking" (conservation for potentially higher value future use) of gas
- a low fixed price, progressively deteriorating in real terms while production and competing energy costs have tended to rise.

These features combined to stimulate Maui production towards the end of the life of the field. Eventually in late 2001, the producers called time, leading to a protracted process to rationalise the Maui arrangements, which has really only come to fruition during 2004.

New Zealand now has an opportunity to diversify its thermal fuel options. The key distinction between the Maui era and the present is that proven developed and undeveloped gas reserves are now low relative to the rate of consumption. The gas situation is providing incentives for additional upstream activity in appraisal, exploration and development. There has been a long-awaited upturn in exploration and appraisal investment, and some preliminary successes, beginning in 2003 and continuing this year.

However, exploration does not create certainty, and major downstream uses of gas are having to weigh the relative strategic merits of waiting and hoping for restoration of an acceptable inventory for which they can bid, or pre-empting exploration results by turning to alternative fuels, of which coal is pre-eminent. Several have taken initiatives to stimulate gas exploration investment directly as well as indirectly.

ECONOMIC ANALYSIS

The economic analysis in this study has three main components. The first examines the effect of developments in the markets for thermal fuels on wholesale electricity prices, followed by the macroeconomic implications of those same developments. Finally, the strategic issues associated with various fuel choices are considered.

The electricity market

In order to assess the effects of changing thermal fuels prices on electricity generation and prices, we have used a plant-level model of the electricity industry based on the same logic as the wholesale electricity market. This model is capable of replicating observed market outcomes when the various New Zealand generators offer into the wholesale electricity market. The assumptions and model structure are described in the detailed project report. In this section, the implications of different scenarios for the wholesale power price are reported.

Base case

For the base case, the calculated electricity price path is shown in Figure 9[4]. It shows the price based on SRMC[5] in all periods; prices rise and fall with new capacity injections, dropping to low prices when large new thermal plants are built. Figure 9 also shows the effect on price of assuming a trend towards a price ceiling based on LRMC[6]. A carbon tax of $15/t CO_2 is assumed to apply from 2008.

As a sensitivity case, Figure 10 shows the impacts of wet and dry year assumptions on price forecasts. Dry year hydro activity is based on 2001 hydro inflows. Very high prices occur in the initial years because of likely limited spare capacity. Whirinaki is assumed to operate at a significant load factor in many years, and there is some demand response. The wet year analysis is based on a 1995 hydro input scenario.

Figure 10 shows that the current electricity system is highly sensitive to dry year effects with somewhat muted effects in wet years. New capacity increments in future years provides adequate generation capacity leading to less sensitivity after about 2011, especially in dry years.

These results illustrate the inadequate overall capacity in the current system. While not a focus of this study, the results also demonstrate the importance of thermal fuels in the New Zealand electricity market, especially for the flexibility they provide.

LNG case

Figure 11 illustrates the impacts of LNG-based gas prices on wholesale prices in an average year and assuming LNG is introduced into the market in 2011. The initial (2011) difference in wholesale price between LNG and the base case assumption is estimated at $12.75/MWh, with an eventual $8.65 (11.4%) difference in LRMC with rising indigenous gas prices.

The initial significant impact of LNG on electricity prices is caused by two factors. One is the increase in gas fuel price from $6.60/GJ for indigenous natural gas to $8.70/GJ in 2011 for LNG and the other is change in the merit order of generation plants caused by higher gas price. This latter effect is illustrated in Table 4 which shows the demand-weighted percentage of time on the margin (i.e. setting price) for several plants under different assumptions. These figures are estimates of the percentage of total generation supplied while specific individual plants are on the margin. It is notable that under the LNG scenario, Huntly becomes more of a baseload plant and has a correspondingly less significant role as a price setting marginal plant.

At a gas price of $8.70/GJ, the older GCC plant are the marginal plants. In other words, natural gas provided by LNG may find it difficult to bid successfully into the market. This would effect a fundamental shift in electricity markets and identifies a significant risk with LNG imports.

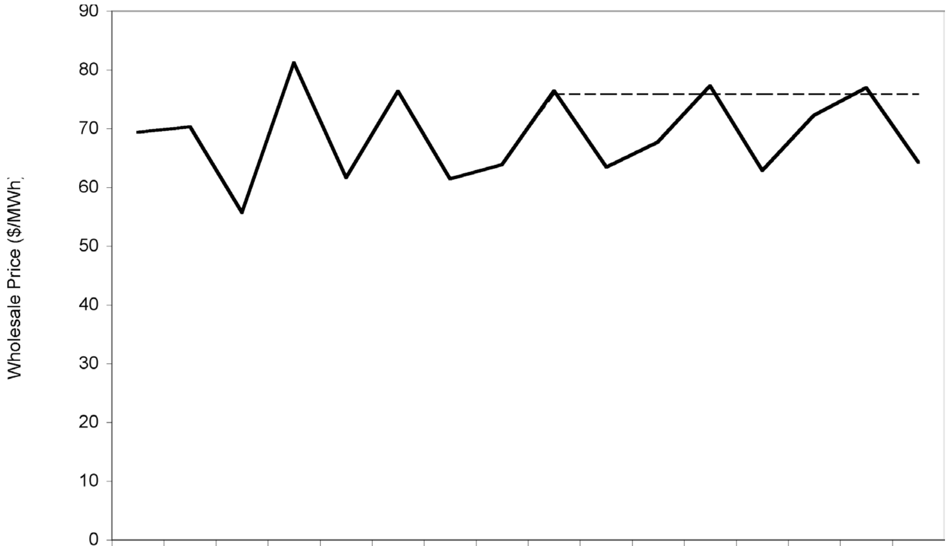
Coal case

An alternative scenario was run in which the new thermal plant from 2011 are coal rather than gas-fired. The results are shown for different assumed carbon charges (Figure 12). There is very little difference in wholesale price between the coal case and the base case at expected levels of carbon charges (i.e. $15/t and $25/t). This exposes another significant commercial risk for LNG, because coal can always compete.

[4] Unless otherwise indicated, electricity analysis in this study is based on average inflows into the hydro system.

[5] SRMC is short-run marginal cost. It is the price at which a plant will find it economic to produce. Thus SRMC covers all short-term variable or controllable costs which may be avoided if the marginal (last) unit is not produced. Short-run marginal price may provide a contribution to fixed costs or unavoidable costs but may not entirely cover them.

[6] LRMC is long-run marginal cost. SRMC cannot be above LRMC. In the long-run, production must more than cover both short-term variable costs and unavoidable fixed costs, otherwise the return on the (plant) investment will be insufficient to justify the investment (and provide equity for replacement or future investment).



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SRMC	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	76.41	63.43	67.79	77.29	62.88	72.32	76.98	64.24
Trend to LRMC	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	75.88	75.88	75.88	75.88	75.88	75.88	75.88	75.88

Figure 9: Future wholesale electricity price path for the base case assuming average hydro inflows and carbon charge of $15/t CO_2 from 2008.

These modelling profiles for the various fuel options are compared in Figure 13 for comparable cases at a carbon charge of $15/t CO_2 and the assumed study fuel prices. The main implications of this electricity market modelling are that the use of LNG as a fuel could result in higher electricity prices than would occur if coal was used to expand the thermal portfolio.

Extending this analysis to a carbon charge of $25/t CO_2 also gives a relative advantage to coal over LNG. This advantage reduces at a coal price of around $6/GJ whilst maintaining LNG prices constant at the $8.70/GJ level.

These results show the importance of good objective and transparent analysis, especially of prices, in considering the thermal fuels future for New Zealand.

Macroeconomic effects

An alternative way to study the impact of LNG

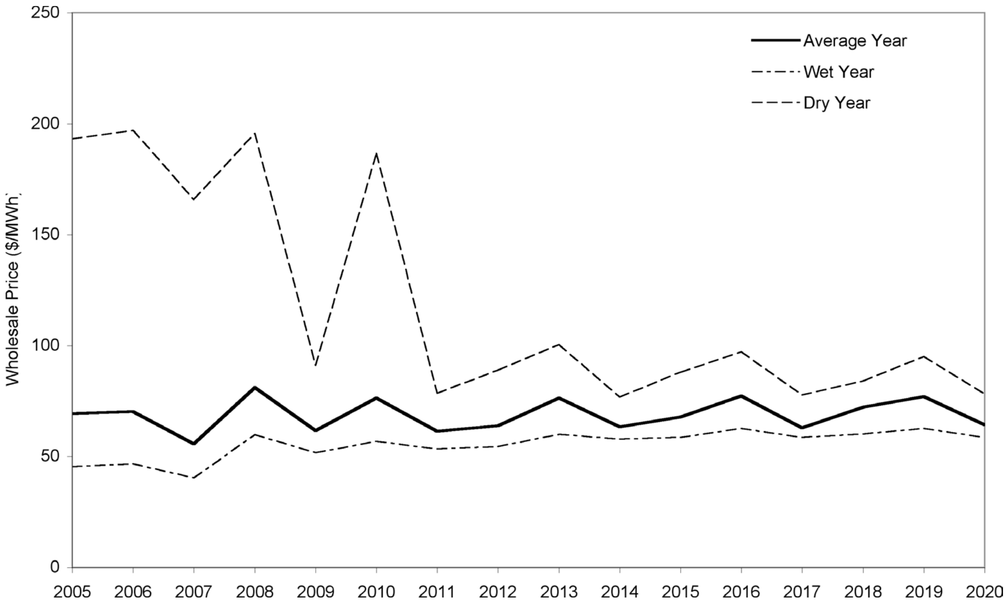
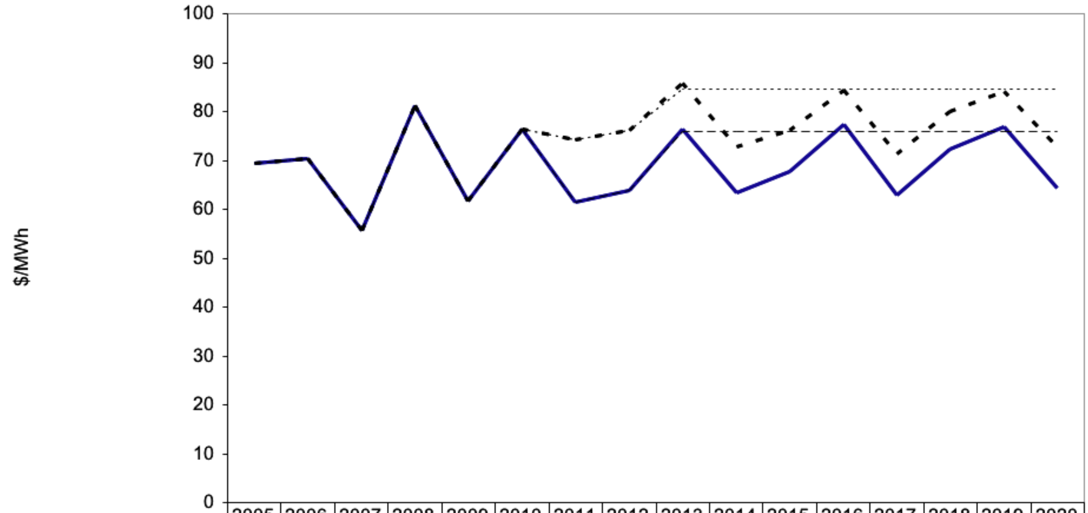


Figure 10: Wholesale electricity price projections—base case assumptions showing the impacts of wet and dry year assumptions on price forecasts.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SRMC	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	76.41	63.43	67.79	77.29	62.88	72.32	76.98	64.24
Trend to LRMC	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	75.88	75.88	75.88	75.88	75.88	75.88	75.88	75.88
LNG SRMC	69.41	70.43	55.67	81.19	61.63	76.34	74.21	76.24	85.83	72.72	76.05	84.44	71.27	79.98	84.16	72.86
LNG LRMC	69.41	70.43	55.67	81.19	61.63	76.34	74.21	76.24	84.53	84.53	84.53	84.53	84.53	84.53	84.53	84.53

Figure 11: Impacts of LNG-based gas prices on wholesale electricity price assuming average hydro inflows and carbon charge of $15/t CO_2 from 2008.

importation is through a general equilibrium analysis. This mode of analysis is capable of revealing the long-run changes in the economy that would arise as a result of a sustained change to the price of energy. This study focused on the differences in the economy in the target year ending March 2017 between the base and LNG cases. As explained further in the project report, it was assumed that several key prices (wages, the cost of capital, the real exchange rate and personal tax rates) would adjust over time to ensure balanced fiscal and external accounts and volumes of labour and capital employed that were consistent with the base case.

The LNG scenario was specified as involving:

- approximately 80PJ of LNG imported
- gas prices of $8.70/GJ, compared to $7.50 in the base case.

Under these assumptions, our modelling predicted a change in the mix of imports rather than the total level of imports, as in the long-run, imports must balance with exports. However since LNG imports are relatively expensive, the terms of trade worsen, and additional exports are needed to avoid an external deficit. Real exports rise by 0.4%, pulling resources out of private consumption which falls by 0.3% which is around $340m per annum in 2004 prices. Taking account of expected population growth, this implies a reduction in real consumer spending power of

	Load Factor (%)		% of Generation with Plant on Margin	
Plant	**Base Case**	**LNG Case**	**Base Case**	**LNG Case**
e3p (Gas)	89.0	62.3	3.3	13.7
OTAB (Gas)	80.5	35.5	8.9	40.1
TCC (Gas)	63.9	15.9	19.1	18.0
New CCGT	90.0	77.7	0	12.6
Huntly (Coal)	20.1	67.7	58.6	5.6
New Plymouth (Oil)	2.7	2.7	10.0	10.0

Table 4: Demand weighted marginal plant (2011) showing the effects of LNG on thermal fuels markets.

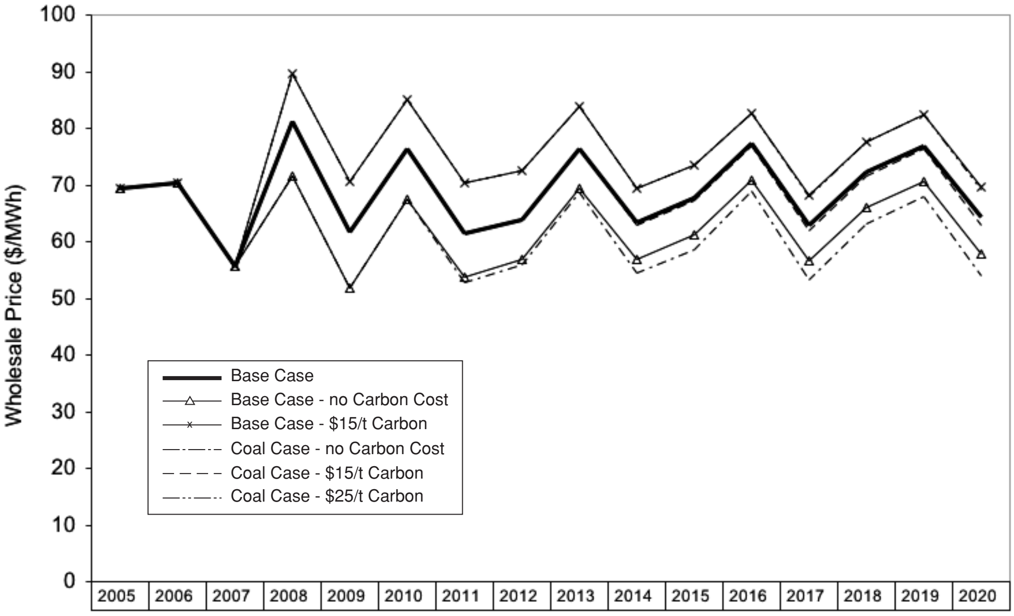
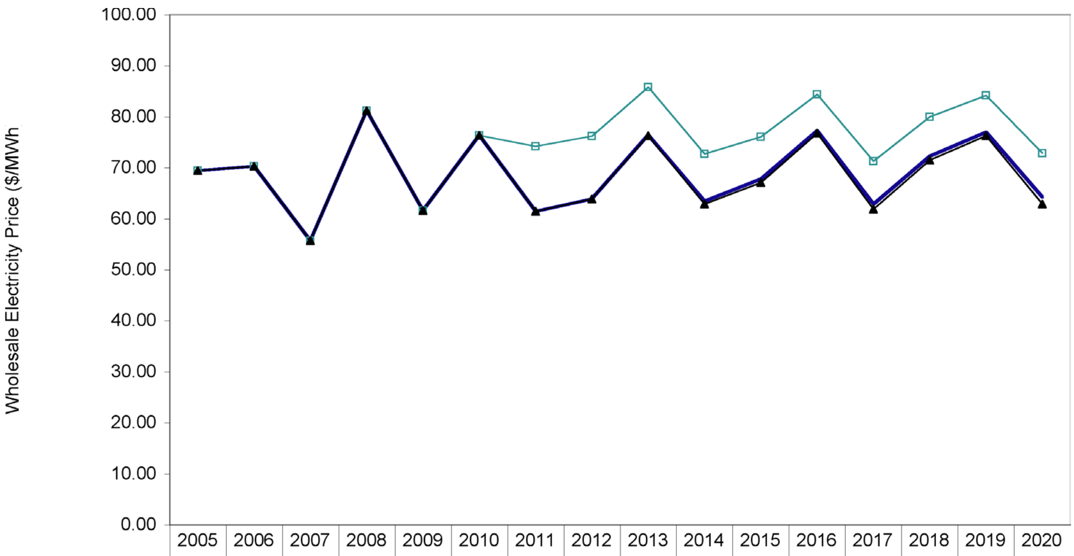


Figure 12: Wholesale electricity price for new coal-fired plant showing the impact of various levels of carbon tax and comparison with the base case.

about $77 per person per year, or an average $220 per household.

The real cost of LNG imports in 2017 is predicted to be $600m. Of this about $300m is paid for by higher exports and lower private consumption, leaving about $300m to be accommodated by a change in the mix of imports. Gas prices are 17% higher in the LNG case as compared to the base case and demand for both gas and electricity is lower.

An important caveat on this macroeconomic analysis, based on a particular view of energy prices, is that it effectively assumes that the structure of the economy will not change materially. In that sense, the LNG scenario outcomes should be seen as a best case view of the future. In particular, it does not envisage any major changes to our industrial mix that



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	76.41	63.43	67.79	77.29	62.88	72.32	76.98	64.24
LNG	69.41	70.28	55.67	81.19	61.63	76.34	74.21	76.24	85.83	72.72	76.05	84.44	71.27	79.98	84.16	72.86
Coal Case	69.41	70.28	55.67	81.19	61.63	76.34	61.45	63.91	76.32	62.86	67.13	76.80	61.90	71.50	76.28	62.91

Figure 13: Comparison of wholesale electricity price for gas, coal and LNG.

Fuel	Location	Price ($/GJ)	Outlook—changes in real prices
Natural gas	NZ-wide	$5[1]	Rising at 4% per annum until 2015 constant thereafter
LNG	NZ-wide	$8.70	Constant in real terms
Coal	Huntly	$3.50 (2004)	Rising to $4/GJ by 2013; constant thereafter[2]
	Marsden	$2.62[3]	Constant
	Southland	$0.79[4]	Constant
	West Coast	$1.20[5]	Constant
Oil	Whirinaki	$15[6]	Constant
	New Plymouth	$11[7]	Constant

[1] This study
[2] MED (2004) New Zealand Energy Outlook to 2025
[3] Solid Energy
[4] Solid Energy
[5] Concept Consulting Group (2004) Project Aqua. An evaluation of the Economic Impact. Prepared for Ministry of Economic Development
[6] Concept Consulting Group (op cit)
[7] Concept Consulting Group (op cit)

Table 5: Comparison of thermal fuel prices

might affect the amount of productive capital and/or labour in the economy, which would not necessarily be the case.

STRATEGIC AND COMPETITIVE EFFECTS

This analysis indicates that LNG is a high cost fuel relative to coal and to indigenous gas. Table 5 above summarises our view of the range of thermal fuel prices.

Given this, we consider that the commercial viability of LNG importation is questionable at present. The most obvious potential buyers of LNG are electricity generators with combined cycle gas plants. These firms would need to consider the possibility of being uncompetitive in the electricity market if their marginal costs are too high. Set against this is the risk of having to adjust their management strategies for existing assets in the event that indigenous gas is not available.

Provided this remains a purely commercial decision, we have no real concerns. This would be fully consistent with the development of competitive markets for electricity generation.

It is nevertheless worth considering how a public policy analysis of this decision might proceed. Imagine for a moment that the generation industry was centrally planned but that we relied upon competitive markets to supply fuels. In this case, a decision over LNG importation would need to trade-off two important factors: the incentives for indigenous exploration, and the value of fuel certainty.

In our view, the effect of LNG importation on the New Zealand gas exploration and production sector would be negative, primarily for scale reasons. Importing 80 PJ of LNG per annum would supply about half of likely demand. The most likely contract structure would involve a long-term commitment to this volume of gas, reducing the size of market available to indigenous suppliers. This would severely limit the range of commercially viable field sizes and deter exploration.

On the other hand, no-one can be sure that sufficient gas will be found and developed in time to bridge the emerging fuels gap, so our "generation planner" certainly needs a fall-back strategy. We would encourage this hypothetical planner to consider the full range of options that are available before committing to an LNG solution. Our investigations show that those involved in the delivery of energy services to New Zealand are beginning to offer alternatives for meeting this country's future thermal fuel requirements. Overstating the risk to supply could result in less preferred outcomes.

discussion

During the course of its investigations into New Zealand's energy future, CAE has sought to address this balance question through a careful examination and objective analysis of the primary technical, commercial and economic factors that characterise the New Zealand thermal fuels market. Our purpose has been to understand the likely ramifications of choosing any one option for meeting future energy needs, and thus develop a picture of the preferred transition pathway from our previous reliance on Maui gas to a sustainable energy future.

THE THERMAL FUELS MARKET

The studies contributing to the investigation have been important in allowing better definition of the current state of the New Zealand thermal fuels market and the likely contributions that can be expected from the various supply side options evaluated.

In summary, several important points can be made:

- The inherent difficulty faced by the New Zealand energy market is one of small scale, and the high risk hurdles to be overcome before new production capacity can be made available to the market.
- The quest for economies of scale within this small market has resulted in heavy reliance over a long period on a single dominant energy source, so that competitive pressures have been dormant during an extended interval.
- As a consequence, the market had become glutted with excess capacity pre-sold, leaving little room for new supply. This reinforced a bias towards oil prospects in the exploration sector, which has been operating at sub-critical mass. Accordingly, there has been little infrastructure development to support an ordered transition from Maui to a post-Maui future.
- With gas scarcity has come more market-reflective prices, which in turn has created positive incentives for exploration. There is now a window of time within which the various alternatives can be considered before serious risk of significant shortages arises.
- The importance of diversity of energy supply on security needs to be underlined. The consequence of foreclosing options at this early stage in the post-Maui transition would have the inevitable effect of reducing diversity.
- The indigenous gas reserves inventory of around 2000 PJ is unsatisfactory, resulting in strong competition for future production offers.
- There is significant potential for further indigenous gas resources, and there are very large coal resources already established. Indications from this study are that future pricing is likely to support their development.

These circumstances set the platform for considering future thermal fuel options for New Zealand.

INDIGENOUS GAS

Our examination of the supply security issue suggests that if New Zealand were to simply rely on indigenous gas from existing developed fields and those known and in development then we are likely to see a gas shortfall occurring at some time early in the next decade.

However, this is not a realistic picture for considering New Zealand's gas prospectivity. The fundamentals for further discovery in the Taranaki Basin are strong and given a reasonable level of exploration, combined with appropriate market opportunity, then there is a good likelihood that inventories can be extended sufficiently to meet requirements out to early in the next decade, the exact time depending on what demand assumptions are used. Beyond this, there is opportunity for significant further discovery in some other basins as well.

With aggressive exploration activity that extends into other regions, a plausible scenario can be presented that could result in a significantly enhanced gas reserves inventory. A considered view on New Zealand's gas prospectivity suggests scope for a strongly emerging gas market in the future, potentially restored to levels of the Maui era, albeit with higher producer prices.

LNG

The counterfactual to this proposition, is that the risk that sufficient new discoveries will not be forthcoming is too great for the New Zealand economy to bear and thus a preferred option is the importation of substitute fuels, or greater use of coal for thermal use. In this scenario, LNG is considered as the substitution option. This does not imply that other thermal fuels are less likely options, but simply reflects the fact that imported gas is in the most direct competition with indigenous gas.

Excluding in-country infrastructure costs the price components of an imported LNG supply are; the ex-liquefaction (FoB) gas price in the country of origin, the shipping cost to New Zealand, and the storage and regasification costs in New Zealand. The analysis reported in this study suggests that the "New Zealand" component of this final supply cost (producer basis ex the regasification plant) is likely to be of the order of 17-20% of the total delivered price. In other words, from a pricing perspective, supply-side risk resides essentially offshore.

Analysis of world markets indicates that LNG is a large-scale capital-intensive industry reliant on an integrated supply chain that is characterised by transfer pricing arrangements and sophisticated sales agreements to mitigate production, transport and commercial risks. There is thus likely to be significant risk in any contractual arrangement that significantly differs from conventional supply arrangements. These arrangements are typified by long-term supplier contracts and pricing formulas linked to the price of crude oil.

It is also apparent that the market is evolving. Contractual arrangements and pricing mechanisms are becoming more diversified so as to more closely reflect the circumstance of the buyer; regional price differentiations are narrowing; and shipping costs are falling, driven in part by increasing scale of the operations and the individual volumes traded.

The question that thus arises is what place in a world market has a small-scale New Zealand facility located at the edge of the Pacific and away from the major trade routes? These vulnerabilities have not been considered here but it seems reasonable to expect that they will eventually drive the commercial risks of a venture, rather than the New Zealand investment cost of the local regasification facility.

The starting point for applying an LNG scenario to New Zealand is a conventional land-based receiving and storage terminal and regasification plant. Study estimates, based on $US 30/bbl crude oil and NZ$0.55/US$1, indicates a delivered gas price of around $8.70/GJ for a 80PJ/year facility, and before the gas enters the transmission and distribution system. At this level of production there would be few economies of scale.

More importantly from a New Zealand perspective, is the influence that commitments to a long-term supply contract for somewhere between 50-65% of New Zealand's total gas demand might have on the residual gas market, and the subsequent outcomes for buyers and sellers.

ALTERNATIVE THERMAL FUELS

Competition for the discovery and development of new indigenous gas resources and competition for the supply of gas from all sources needs to be considered as part of any decision to import LNG into the New Zealand market.

Between the security advantage of imported LNG and the competitive advantage of hoped-for discovery and development of indigenous natural gas, there is a range of alternatives that could combine to give more optimal solutions or preferred outcomes. These options include:

- coal, either imported or indigenous
- smaller scale imported LNG based on a floating gasification facility
- imported Liquefied Petroleum Gas (LPG)
- imported Compressed Natural Gas (CNG)
- imported liquid fuels and their derivatives such as naphtha.

The various options have been summarily

explored in this study and we conclude that whilst coal seam gas, liquid fuels and LPG, in particular, could increase their market share in some niche applications they are unlikely to be significant additional contributors to the thermal fuels market in this country[14].

Coal, however, offers significant flexibility for a market place that is already constrained by seasonal demand profiles and dry-year effects within the electricity segment of the market.

There are abundant resources of suitable coal for expansion for direct use and electricity generation in several regions, especially the Waikato and on the West Coast of the South Island. The extensive low-rank coal resources of the south-eastern South Island are less favourably located with respect to major load centres and their development is more likely to be focussed around future opportunities for chemical and liquid fuels production to meet New Zealand's emerging demand for a sustainable primary fuels base.

In respect of CNG, its greatest challenge lies in the shipping segment of the supply chain with approximately 80% of the total supply cost tied-up in the shipment of the fuel. On the other hand, CNG offers the advantages of modularity and flexibility. Implementation of this option would require much greater understanding of the technical and supply risks.

The impact of an LNG project on the size of the gas market is thus of considerable importance. The component of this market that needs to be considered is the volume of demand that could be served by an indigenous producer, since this is what feeds into such a firm's investment analysis. This market will be reduced by low-usage costs for potential substitute fuels such as coal and CNG. It will also be reduced by the pre-existence of long-term contracts for gas supply from existing producers, since the volume of gas covered by such contracts is not contestable for a new supplier.

[14] This assumption ignores the potential for significant increased penetration of LPG into the automotive fuel market to assist in meeting greenhouse gas limits on that market.

ECONOMIC EFFECTS OF LNG IMPORTATION

In this study we conservatively estimate that the core demand for natural gas in New Zealand today is around 110 PJ a year, with additions of about 20 PJ every three years as new power stations are required to meet growth in electricity demand. It would seem unlikely, therefore, that an LNG project at the assumed 80 PJ/year threshold scale could proceed in the New Zealand context without significant adverse competition effects.

Beyond this consideration is the additional factor of the likely requirement for long-term contracts for LNG, as this will have the largest potential impact on the size of the contestable gas market. LNG importation would not be a risk-free project. The primary risk is that the delivered cost of gas imported as LNG is materially higher than the projected average delivered cost of indigenous gas, or becomes so during the anticipated life of the contract.

If this situation transpires, some or all of the sunk capital invested in the LNG project could potentially be stranded. Whether such stranding would actually occur would depend on the structure of the contract that underlies the importation of the fuel, and any in-country arrangements for on-selling the gas.

Consideration of the range of contractual arrangements that might manage this risk is beyond the scope of the study. Instead, analysis was undertaken of the relative costs of electricity derived from a business as usual case, which allowed for natural gas discovery and development as well as inter-fuel substitution by coal, against an LNG import case. This analysis allows some estimate to be made of the likely vulnerability of an LNG project of being exposed to import prices greater than the alternatives.

Our preliminary analysis of the different scenarios suggests that an LNG price is likely to be 15-20% higher than indigenous gas by the year 2017. This price premium, if forced onto the electricity generator, will translate into increased electricity costs of around $3.50/MWh in LRMC and a reduced demand from substitution and destruction of low-value electricity load.

The implications of these effects have been further analysed through the use of general equilibrium modelling of the New Zealand economy. The main effect of the demand for imported LNG is to change the mix of imports rather than the total level of imports. This in turn impacts adversely on terms of trade, implying that exports will need to rise to pay for the increased costs. Exports are likely to rise by about 0.4% in value resulting in a fall in private consumption of about 0.3%. This effect is equivalent to a net reduction in household spending of about an average of $220 per household. At the limit assumption, where LNG meets the entire thermal fuels market, the reduction in private spending falls to about $290 per household per year.

In addition to these impacts, an increase in the price of gas will have a direct impact on major energy users. The critical issue for these users is the pricing level at which there is no new investment, but with operations continuing at plants with sunk costs, and at which variable costs cannot be covered and operations cease. This situation has already emerged, e.g. operations at the Methanex methanol plants in Taranaki have dropped to less than half of capacity and are forecast to drop further next year. The impacts of such closures are several fold:

- reduction of the total demand for gas in New Zealand, thereby reducing the incentives for further exploration
- loss of the capacity to use large-scale loads as a swing element to optimise gas field production management and (for example) moderate seasonal demand effects for electricity generation
- reduction of asset values for New Zealand's primary sectors (forest, mineral and farming), as well as manufacturing itself, because of the impact of higher costs on profitability.

Based on this analysis, assessment of future fuel options should be particularly concerned with a situation in which the delivered cost of LNG exceeds the expected prices of indigenous gas or other alternatives.

The position of a potential LNG buyer, such as a thermal electricity generator committing to buy LNG at a price in excess of the price of locally produced gas, is that it risks being unable to secure economic dispatch in the electricity market as a result of competition from rivals using indigenous gas. This risk seems unlikely to be willingly shouldered by any generator acting alone.

An obvious risk mitigation strategy would be to form a joint venture of all gas-fired electricity generators (or at least a dominant sub-set of) for the purpose of buying LNG. Such a joint venture would actually be able to contract for LNG at a price in excess of indigenous gas cost without fear of competition from generators using local gas. It is difficult to imagine that such an arrangement would be authorised by the Commerce Commission. However, if this situation did materialise, the incentives for local exploration and development would be materially reduced as a result of the removal of a large pool of previously contestable gas customers.

Clearly, if a fully commercial case can be made for LNG then it will go ahead. If not, then there are a number of possibilities that might arise. One is that Government might commit to LNG for energy security reasons, either directly or by underwriting a commercial investment. If this option were to be pursued then the issue becomes one of public policy and will presumably require extensive consultation and dialogue with industry players and consumer advocacy groups.

Current energy policy framing does not readily allow for coherent attention to this issue, in spite of evidence of the necessity for intervention in other areas of the energy market. The lack of a coherent view in this country on our preferred future pathways suggest the way ahead will be fraught with difficulty.

OPTIMAL THERMAL FUEL STRATEGIES

Commitment to an LNG-secured pathway ignores the range of other possibilities for meeting future demand. As well as further development of coal, and discovery and development of indigenous gas, technical options for future supply include an LNG regasification vessel, and CNG. Competition between these options, whilst offering the potential for reduced long run energy prices, will most likely result in greater volatility of prices. In this hybrid supply case, an LNG import component can be envisaged based around a developed physical infrastructure supported by Government investment, with gas supply contracts open to generators and producers alike.

Opening New Zealand to a spot market for thermal fuel has the potential to incentivise least-cost solutions whilst also managing long-term supply risk. If the world price for LNG, LPG, CNG or coal was very low one might expect that the development and production of indigenous resources would be throttled back. At times of high international prices local production would have an advantage and import facilities would be less extensively used.

The main conclusion from this analysis is therefore that security does not necessarily require that our economy become locked into any one single option. The importation of LNG, whilst superficially attractive from a security of supply perspective, raises significant public policy issues and needs to be closely examined from a national economic perspective.

Other alternatives are available and, on balance, current energy inventories are likely to be able to meet future needs out to early in the next decade. Indigenous natural gas supply is potentially manageable now that a large tranche of consumption, in the region of 60-90 PJ/year, has been attrited due to both deliverability and price factors. Continuing sufficiency is conditional on undeveloped reserves in the Pohokura and Kupe fields being developed according to plan, and new discoveries being made soon and brought on stream promptly.

A premature decision to import LNG would act to discourage local gas exploration and coal development and thus inevitably lead New Zealand to a future of high energy cost and constrained economic growth.

conclusion

This is the first independent study to bring to public attention the issues surrounding the need to achieve energy security in this country, and the policy and strategic reference frames in which key decisions will need to be taken in the transition from the depletion of the Maui gas field.

The investigations covered in this report are far-reaching. While it has not been possible with the resources available to the study team to cover all the various issues in depth, we have sought to bring together the key elements that will be important in framing future decisions on meeting New Zealand's future thermal fuel requirements, and the choices we might have.

The most obvious conclusion is that there are significant uncertainties surrounding forward projections of demand and the likely consequence of any adopted strategy. Foremost amongst these uncertainties are issues surrounding:

- The complex amalgam of transactions that currently define our thermal fuels market, and the likely future behaviours of the major and potentially dominant players.
- The relationship between fuel price and demand, contractual structures and the likely responses of major consumers with regard to fuel substitution and demand shedding.
- Industry views as to what constitutes adequate strategic energy reserves.
- The likely response to rising gas prices by the exploration sector.
- The market dynamics that could improve prospects for developing some of New Zealand's underdeveloped and in some cases undiscovered energy resources.
- The potential economic effects from the imposition of the carbon tax and how this might ultimately influence the competitive position of gas versus coal and other options.
- The likely implications to the New Zealand economy and its international competitiveness from a change in the volumes and mix of fuel imports.
- Modelling approaches that can accurately describe future electricity wholesale process.
- The economic value to the New Zealand economy of diversity of energy supply.

These factors, and the myriad of second order effects, will actually determine the ultimate outcome for New Zealand. Our understanding of them is thus critical to arriving at decisions which lead to an optimal energy supply strategy for this country. In this study we have attempted to develop and explore these issues so that their relative importance and influence can be evaluated.

What we have discovered is that there is little hard evidence to support many of the influences identified. Instead we have been forced to rely in many instances on anecdotal evidence in bringing together our thinking and judgements. Where it has been possible to bring together quantitative analysis we have done so to a first order level. More needs to be done.

Whilst some of this work will undoubtedly be undertaken at an enterprise level as a normal part of in-house strategic planning, the difficulty for New Zealand is that such analysis does not generally reside in the public arena. If it is presented in public reports, the work is not robustly debated or thoroughly examined from a public policy perspective.

The challenge for New Zealand is to balance security, risk, economic competitiveness and the value of fuels diversity. The key questions for New Zealand are:

- what constitutes an adequate strategic reserve capability sufficient to facilitate the ordered and sustainable development of our thermal fuels market, and
- what contribution to this market might be made from indigenous fuel sources.

At one end of the energy security scale, certainty of supply can be achieved by investing in “gold-plated” solutions that might guarantee supply but at the expense of overall economic efficiency. At the other end of the scale we can adopt a laise faire approach, accepting higher supply risk in return for hoped-for advantage in lower energy costs and improved competitiveness. The optimal balance lies somewhere between these two extremes.

We argue that to arrive at this balance point, there is a need to have a much clearer view of the implications of different supply options and the public policy imperatives that would underpin any commercial undertaking in support of any the alternative pathways identified in this report.

This study has crystallised several knowledge keystones within which the options and public policy imperatives can be considered:

- The inherent difficulty faced by the New Zealand energy market is one of scale. In a small market the likelihood for market dominance is high, and the competition effects of any future option need to be explicitly addressed in ways that are transparent to the market as a whole while allowing for competitive outcomes.
- The fundamentals for further gas exploration success are good and with a higher level of exploration activity there are good prospects for restoring New Zealand’s gas inventory to a level that would improve energy supply security and give energy markets a higher level of certainty.
- New Zealand thus has a window of opportunity available to it of some few years before any decision needs to be made on the next tranche of fuel supply. A premature decision to import LNG would act to discourage local gas exploration and possibly coal development and would lead the country to a future of high energy cost and diminished economic performance. There are alternatives deserving of more attention.
- For major energy users the price of gas will be critical. Demand destruction within the petrochemicals and primary industry sectors reduces New Zealand gas demand and thus the incentives for exploration. Higher costs will also adversely impact on the competitiveness of the primary production and processing sectors and hence on the economy as a whole.

Security of energy supply in the post-Maui era does not require our economy to lock into any one thermal fuel option. Dealing with supply shortfall is not simply a question of reducing risk at any price or seeking certainty; instead, it demands responses that will extend our primary energy resource base, restore inventories to cover a strategic reserve capacity and enable long-term investment in alternative sources.

But perhaps most importantly, this study reinforces the view that, because of New Zealand’s small energy markets and the impediments to investment in upstream activity, we are unlikely to ever see a purely commercial decision related to future supply infrastructure. In this environment, the choice to import fuels raises significant public policy and economic issues. Analysis of these issues remains a vital component of future energy planning in this country.

No matter what path we go down, we need to avoid over-dependence on a single option. Commercial proposals should be required to look at the full range of options and public policy must examine the trade-offs between encouraging indigenous thermal fuel development and the risks associated with striving for fuel certainty.

Ultimately the challenge for New Zealand is to balance security, risk, economic competitiveness, environmental outcomes, and the value of fuels diversity so as to deliver the best macro-economic outcome for New Zealand.

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STUDY TEAM

The technical study team which produced the detailed analysis from which this report was derived comprised: Reuben Bouman, University of Canterbury; Mac Beggs, GeoSphere; Ian Coard, Chevron Texaco; Tim Denne and John Small, Covec; Gary Eng; George Hooper, CAE; Graeme Oakden, Oakden Consultants; and Alan Sherwood (editor).

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This document is the work of the CAE study team and does not necessarily reflect the individual views of the sponsors.

feedback

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